Oil and Gas Finding Costs

Russell S. Uhler

CANADIAN ENERGY RESEARCH INSTITUTE

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Preface

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June, 1979

Chapter 1

INTRODUCTION AND SUMMARY

Future increases in recoverable reserves of crude oil and natural gas in Canada will come from several sources. They are: (1) existing producing oil and gas reservoirs; (2) known reservoirs which are not currently in production; and (3) the discovery of new reservoirs. Recoverable reserves in producing reservoirs are regularly revised as the physical conditions of these reservoirs change and as economic and technical conditions improve to make it worthwhile to recover a higher proportion of reserves in place. As the price of oil and gas rises, for example, it often becomes worthwhile to embark upon further development drilling and to initiate or extend secondary recovery operations and thus expand the amount of recoverable reserves in a reservoir. The Lloydminster field in Alberta is a case in point. It has been producing heavy crude oil for many years but recent increases in crude oil prices and advances in recovery technology have resulted in an extensive upward revision of estimated recoverable reserves from this field.

Another major source of additional recoverable reserves is from reservoirs which have been known to exist for years but which were uneconomical to produce. Until a few years ago the Milk River formation in the recently designated Southeastern Alberta field was such a source. Natural gas was first discovered in this formation in the early 1900s but economic conditions in gas markets did not make extraction a worthwhile venture. However, improvements in these markets have led to a re-evaluation of the potential recoverable reserves in this field so that between 1973 and 1976 a large percentage of the total additions to gas reserves in Alberta came from this field alone. Another example is the very heavy oil deposits in the Cold Lake area of Alberta. Improved economic conditions and new technology stimulated by these improved conditions may result in substantial increases in recoverable reserves from this area.[1]

A third source of additional recoverable reserves, and the source upon which this study will focus, is the discovery of oil and gas in new reservoirs. The Western Canadian sedimentary basin may still contain significant amounts of undiscovered reserves of crude oil and natural gas but if they become increasingly more difficult to find

then their costs will rise. To the extent that oil and gas prices remain above total per unit finding, extraction, and royalty costs in this basin, economic incentives for exploration activity will continue to exist and new reserves can be expected to be discovered. But the important question is: will the total production costs of these discoveries be low enough to stimulate enough exploration to result in significant levels of new discoveries? Knowledge of the costs involved will help to answer this question.

The purpose of this study is to focus on those costs which are associated with finding new crude oil and natural gas reserves. The costs of development and extraction are not considered in this study.[2] Finding costs are determined by specifying and estimating production functions for oil and gas discoveries which relates the exploratory inputs, drilling effort, land holdings for exploratory purposes, and geophysical activity, to discoveries of oil and gas. Knowledge of the prices of these inputs and their associated outputs allows finding costs to be determined directly from the estimated functions. The approach which is taken here is thus to model the oil and gas discovery processes so that it is possible to understand more clearly why historical costs were what they were and to better be able to forecast future finding costs. Two basic oil discovery models and one gas discovery model are specified and estimated. In addition to the exploratory inputs, one oil discovery model introduces the occurrence and structure of oil 'plays' explicitly whereas the second is more aggregated, requires less information, and imposes less structure in this respect. Both oil models are used to produce estimates of finding costs. Both show substantially rising oil finding costs in recent years but tend to underestimate observed levels. These finding costs are also compared with wellhead prices and it is found that the price-to-finding-cost ratio has fluctuated in response to major new plays but has generally declined over time.

The gas discovery model is similar to the oil model which does not explicitly incorporate the effects of new plays. In fact, it is suggested that until recently the right set of economic conditions has not existed in Alberta to generate gas plays in the usual sense. Gas finding costs are estimated from this model, and it is found that the price-to-finding-cost ratio for gas exploration is now better than for oil which partly accounts for recent substantial reallocation of exploratory inputs away from oil-intent exploration and toward gas-intent exploration. The shift of interest towards gas also reflects the difference in the after tax return to gas. Gas exports have not been subject to the special federal export tax as have oil exports.

On the other hand, delays in marketing recent gas discoveries may have shifted interest the other way again, especially in the light of oil discoveries in West Pembina.

These results have a bearing on the recent assertion by the industry that increased exports, especially of natural gas, should be allowed in order to generate revenues to finance more exploration which in turn will produce even more recoverable reserves. Of course, more exploration will produce new reserves of both oil and gas. But the crucial question is, how much? The findings of this study are that both oil and gas, but oil more so than gas, are becoming increasingly more expensive to find. Eighty-five percent of all of the recoverable oil found in Alberta has been found in five major oil plays so that unless another major play is discovered finding costs can be expected to continue to rise. Unfortunately it does not seem to be possible to develop a model which can forecast such a rare event as a major new oil play. Although the first oil model developed in this paper is useful for forecasting the impact of new plays on subsequent discoveries and finding costs it does not have the capability of forecasting the time of discovery of a new play. For example, West Pembina could not have been forecasted but the model is able to predict how such a discovery can affect subsequent discovery rates and finding costs within all known plays. This matter is taken up in Chapter 4 of this study.

With respect to natural gas the situation is somewhat brighter in that the ratio of the composite price (including gas byproducts) of gas to finding costs appears to be around 2.5 as opposed to close to 1.0 for oil. The price-finding-cost ratios for both gas and oil are higher when finding costs predicted by the models are used. As in the case of oil, the ratio has fallen substantially over the years so that unless a major new gas play is discovered the prospects for gas are not exceptionally bright either. It does seem, however, that the chances of finding major new accumulations of gas are better than for oil. This seems especially likely if one believes that until relatively recently economic incentives for generating true gas plays have not been very strong.

One of the features of the models is that they also yield information on the substitution possibilities among the exploratory inputs and on the response of these inputs to changes in their own prices and to changes in the prices of the other inputs. It was found that exploratory drilling and geophysics are substitutes in the discovery process. Possibly more surprising is that drilling and land are found to be substitutes in the early years of exploration in

Alberta and complements in the later years. An interpretation of this result is given later. Not surprisingly, land and geophysics are complements in the discovery process. Drilling is found to be relatively price inelastic, land has a price elasticity near unity, and geophysics is relatively price elastic meaning that of the three inputs drilling responds least to changes in its own price and geophysics responds most to changes in its own price.

Chapter 2 contains an overview of petroleum exploration activity in Alberta by studying the time patterns of oil and gas discoveries and of the exploratory inputs. This overview is of interest in its own right but it also provides a basis for the formulation of models of the discovery process provided in Chapter 3. Chapter 4 deals with the estimation of the models which leads ultimately to the determination and interpretation of oil and gas finding costs. The forecasting capability of these models and certain other matters are also discussed in Chapter 4.

Footnotes

[1]For a description of the prospects of recovering heavy and very heavy oils of the Lloydminster and Cold Lake variety see Canada, Department of Energy, Mines and Resources, Oil Sands and Heavy Oils: The Prospects (Ottawa: Department of Energy, Mines and Resources, 1977) Report EP 77-2.

[2]Even though the economics literature contains numerous instances in which theoretical cost relationships are specified for the purpose of studying the best resource extraction time path there are relatively few studies which actually attempt to estimate these cost relationships. In the case of petroleum extraction and development some exceptions are: P. G. Bradley, The Economics of Crude Petroleum Production, (Amsterdam: North Holland, 1967); G. C. Watkins, "Proration and the Economics of Oil Reservoir Development, Province of Alberta, Canada," December 1971. (Manuscript.); and P. C. Eglington, "The Economics of Industry Petroleum Exploration" (Ph.D. dissertation, The University of British Columbia, June 1975).

Chapter 2

PETROLEUM EXPLORATION IN ALBERTA

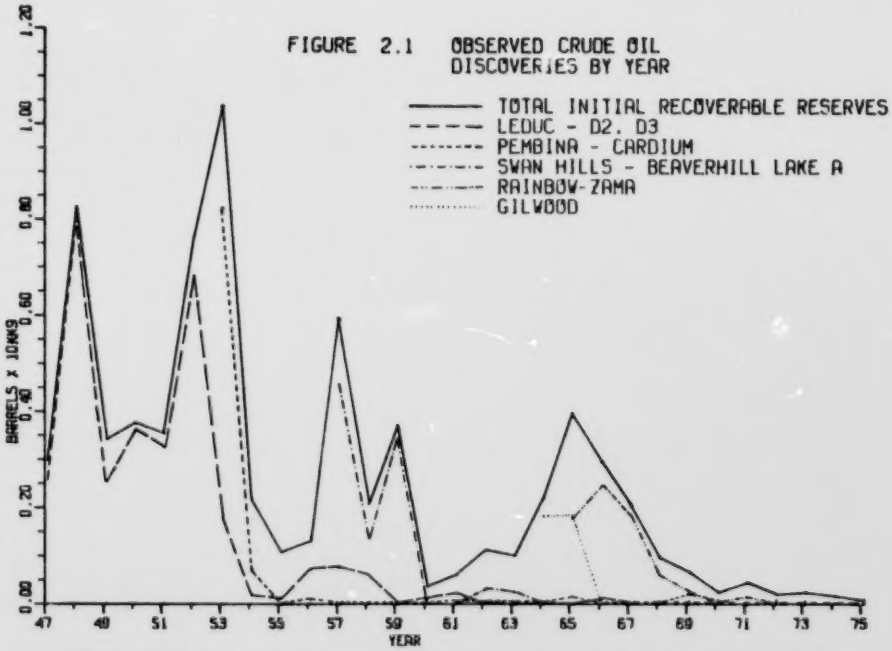
In this chapter an overview of petroleum exploration activity in the Alberta sedimentary basin from 1947 to the present is given by studying the way in which the main variables associated with exploration activity have behaved over time. By so doing it may be possible to gain insights into the nature of the exploration process which will help in formulating appropriate economic models of this activity. In addition, such an overview provides evidence on the extent to which the analysis of such historical data can be used, either within or without the framework of a formal model, to make forecasts of future events. It is, of course, in such forecasts that we are particularly interested. The historical analysis begins with a description of the time pattern of discoveries of crude oil and natural gas followed by a description of the measurement and time pattern of exploratory drilling activity, land acquisition, and geophysical effort. The treatment of the land input and the measurement of geophysical effort are issues of particular interest and are given appropriate attention.

2.1 Oil and Gas Discoveries

The upper solid line graph in Figure 2.1 shows aggregate yearly discoveries of initial recoverable reserves of crude oil by all categories of discovery wells.[1] What is of special interest about Figure 2.1 is that it shows clearly that oil discoveries in Alberta, as elsewhere, have come in great waves or cycles, each of which can be associated with a major oil 'play', i.e., the discovery of significant accumulations of oil in a particular geological formation.

In order to emphasize the importance of particular oil plays in total discoveries the yearly amounts of initial recoverable reserves discovered in each of the five major oil plays are also plotted in Figure 2.1. It is clear from inspecting this figure that beginning with the Leduc D2 and D3 play in 1947 followed in succession by Pembina, Swan Hills, Gilwood, and Rainbow-Zama oil discoveries in these plays have made up the great bulk of total oil discoveries. Thus we see that the information that a major accumulation of oil existed in

FIGURE 2.1 OBSERVED CRUDE OIL DISCOVERIES BY YEAR



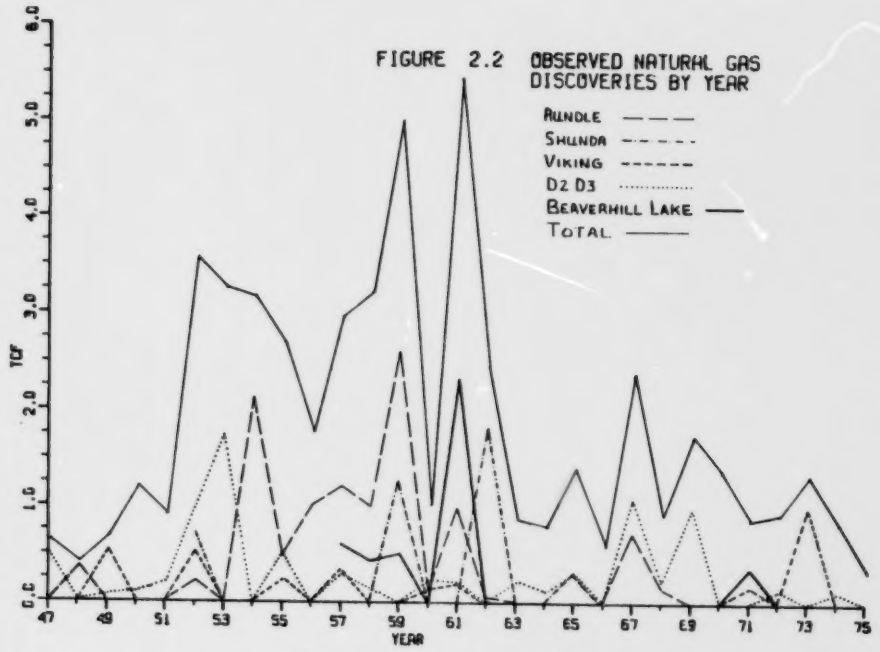
Source: General Well And Oil Reserves Files, Alberta Energy Resources Conservation Board(ERCB)

each of these five groups of geological formations has led to nearly all of the oil discoveries in Alberta.

Further study of Figure 2.1 reveals another interesting observation which will later assume a crucial role in modelling the petroleum discovery process. It is that the pattern of discoveries in each play follows the roughly similar pattern of high initial discovery rates followed eventually by a sharp decline leading to quite low discovery rates. Sometimes the discovery rate grows initially and then declines as in the case of the Rainbow-Zama play and sometimes it starts out at a high level and declines steadily as in the case of Pembina. Leduc and Swan Hills each have two peaks but again they appear in the initial years and are followed by several years of relatively low discovery rates. The scale on the graph is such that these amounts in late years of a play are often barely noticeable. To summarize, we note that the within play pattern of discoveries is one of high initial levels of discoveries followed by sharp declines trailing off to relatively low levels. On the other hand, the pattern of aggregate discoveries, being essentially the sum of the within play discoveries, is much more irregular since plays begin at different points in time and vary in size.

The pattern of aggregate initial marketable gas reserve discoveries is roughly similar to that observed for crude oil as evidenced by the major cycles which are prominent in Figure 2.2. However, it is also apparent that this aggregate does not conform to the total of the reserves discovered in the major gas producing formations nearly as closely as in the case of crude oil. The reason is that there are more gas producing formations and many reservoirs with relatively small accumulations of natural gas. But what is particularly noteworthy is that the pattern of gas discoveries within specific formations is usually different from the pattern observed in oil bearing formations. Rather than quickly reaching a peak followed by a decline, formation specific gas discovery rates are often spread out over a much longer period of time. The major accumulations in the Rundle and Viking formations and in Leduc are clear examples of this pattern.

Why should we observe such a difference in the pattern of oil and gas 'plays'? Most of it can probably be explained by economic conditions in gas markets which have existed over much of the period. Most of the major low cost sources of gas were found incidental to the search for oil. During most of pre-1960 period market conditions for natural gas were such as to discourage major waves of discoveries in



Source: General Well and Gas Reserves Files, ERCB.

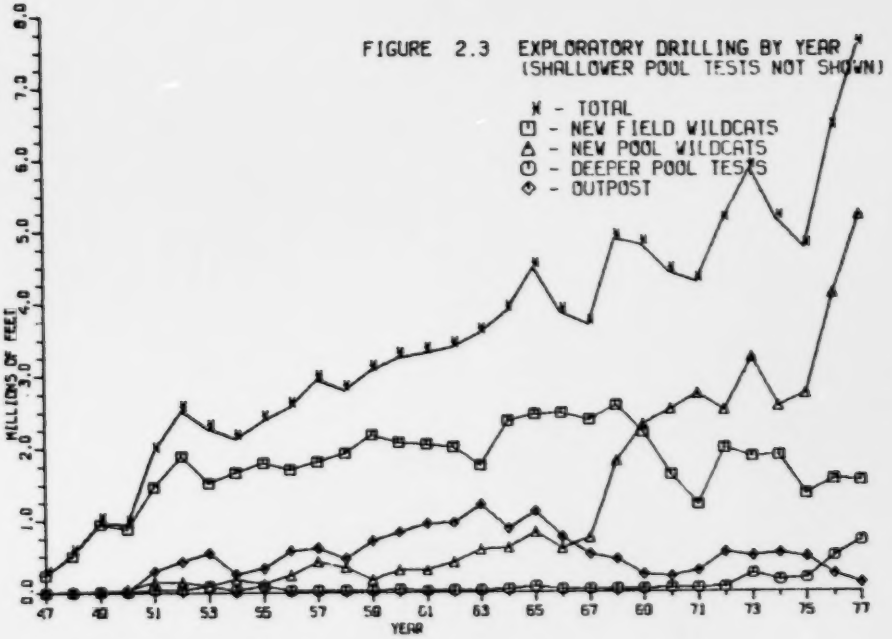
gas producing formations. However, through much of the 1960s gas markets improved thus creating the incentive to search for gas in formations which had already been proven to contain significant accumulations. Under these conditions it is not surprising that gas play activity would show a pattern of discoveries which was more spread out over time. Recent dramatic improvements in natural gas markets might lead to gas plays that exhibit a pattern which is much closer to what has been observed for crude oil in the past.

2.2 Exploratory Drilling Effort

As noted earlier the three categories of exploratory inputs are geophysics, land, and drilling effort. In this section various aspects of exploratory drilling in Alberta will be discussed. Drilling for oil and gas involves the usual economic inputs: labour; capital; and materials in the form of drilling crews, drilling rigs and other equipment, etc., but rather than attempt to measure directly the level of use of these inputs a more aggregate measure of drilling effort which nevertheless reflects the intensity of use of these inputs will be chosen. Two alternative aggregate measures are available: (1) the number of exploratory wells drilled per unit of time; and (2) the amount of exploratory footage drilled per unit of time. In this paper the second of these alternatives will be used.

An overview of exploratory drilling effort in Alberta since 1947 is presented in Figure 2.3. It shows the total footage drilled per year in each of the exploratory well categories and the overall total. In response to a sequence of major oil plays beginning with the discovery of oil in the Leduc D2 and D3 formations in 1947, new field wildcat well footage grew steadily until the late 1960s. Failure to locate good prospects in new producing formations following the Rainbow-Zama play combined with what, at the time, appeared to be brighter prospects in other regions led to a sharp drop in the level of new field wildcat activity in Alberta. However, new pool exploratory well footage expanded rapidly during this period to more than offset the decline in new field wildcats. Apparently in the late 1960s prospects in existing fields were relatively attractive but later the surge in new pool exploratory activity was to exploit an 'inventory', primarily of gas structures which became economically attractive as markets for gas improved. More recently the Alberta exploration incentive program has probably also contributed to an increased level of exploratory activity.

FIGURE 2.3 EXPLORATORY DRILLING BY YEAR
(SHALLOWER POOL TESTS NOT SHOWN)



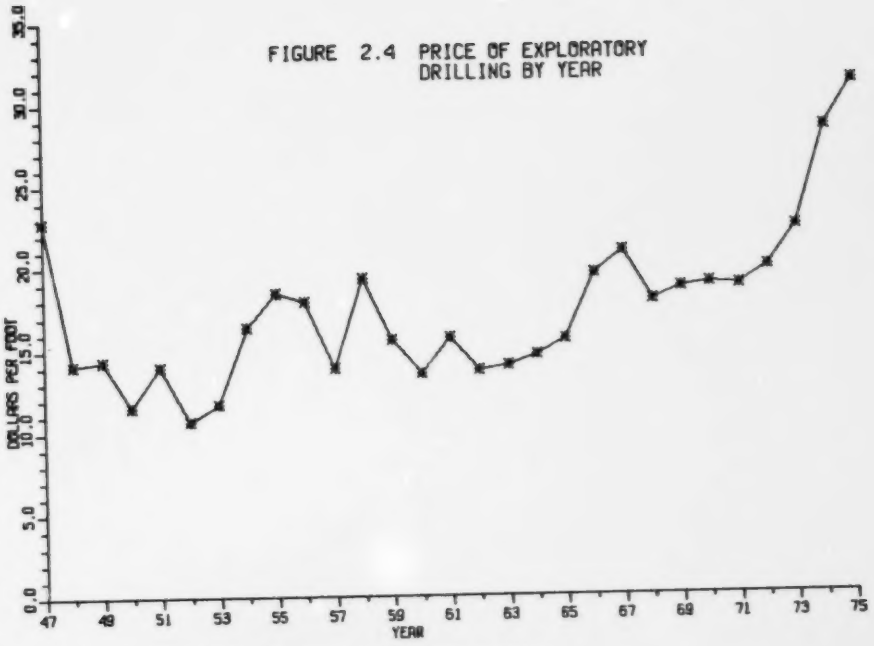
Source: General Well File, Annual and Cumulative Statistics, ERCB.

What is particularly noteworthy about Figure 2.3 is that the overall level of exploratory activity does not seem to have closely followed the pattern of discoveries. Whereas oil and gas discoveries have followed a cyclical pattern mainly due to the influence of major plays, total exploratory drilling activity has followed a rising trend with a couple of peaks which might be linked to the effect of major plays. Contrary to what might be expected it would appear then that the level of exploratory drilling effort provides a poor explanation of the discovery rate. However, in the petroleum industry the variation in the output (discoveries) for any given level of the inputs is due primarily to the existence of major petroleum plays. Thus it is the discovery of a play in petroleum exploration which creates a kind of extreme random element affecting discoveries as weather is, for example, a random element affecting agricultural output. The difference is one of degree but, like the weather, the recognition of petroleum plays presents a formidable challenge to the model builder.

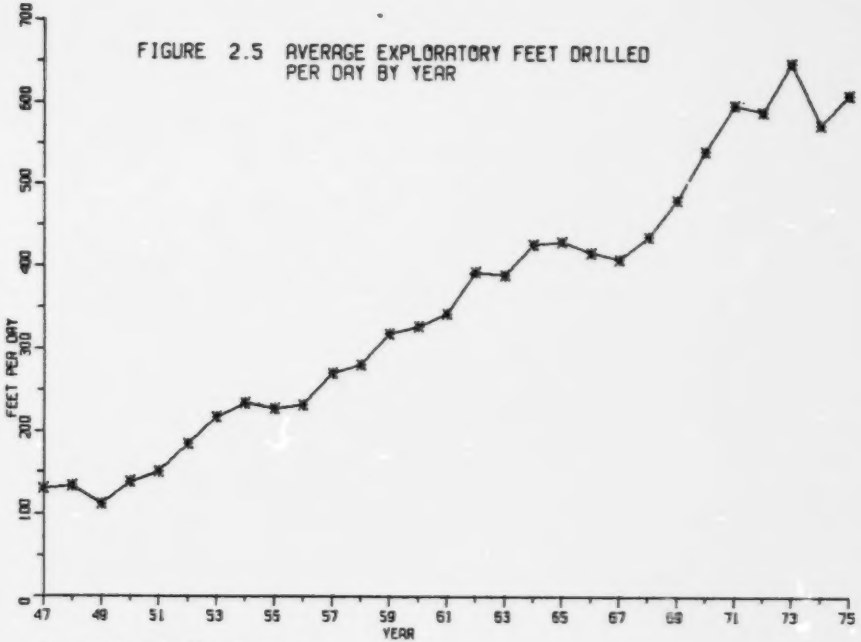
If the other exploratory inputs follow a pattern over time which is similar to that followed by exploratory drilling effort one would be led to the conclusion that the cost of oil and gas discoveries fluctuates over time; being low in the midst of major play discoveries and higher at other times. But before jumping to such a conclusion it is necessary to study the pattern of expenditures on these inputs not just the physical amounts employed. If the unit costs, or prices, of these inputs have changed over time the conclusions would be altered. It is for this reason that I now turn to the consideration of the price of and expenditures on exploratory drilling. The other input categories will be considered later.

The price (cost per foot) of exploratory drilling is easily calculated by dividing exploratory drilling expenditures in each year by the footage drilled.[2] This price series is shown in Figure 2.4. What is particularly interesting is that prices have remained remarkably stable over most of the period in question. Up to 1972 it is hard to argue that prices had increased at all even though the prices of labour and material inputs had risen rather substantially over this same period. The explanation for the relative stability of drilling prices in the face of rising basic input prices is improvement in drilling technology. Since the cost of drilling a well is nearly proportional to the time spent drilling, increases in drilling speed will naturally reduce costs. The importance of improvements in drilling technology are illustrated in Figure 2.5 which shows the time pattern of feet drilled per day. The figure shows dramatic improvement in drilling technology up to 1972 after which it levels off. It would

FIGURE 2.4 PRICE OF EXPLORATORY DRILLING BY YEAR



Source: General Well File, Annual and Cumulative Statistics, Exploratory Dry Well Costs, ERCB; Statistical Yearbook, Canadian Petroleum Association.



Source: General Well File, ERCB

seem therefore that technological improvements have been such as to offset the effects of increases in basic input prices to the extent that, up to 1972, a nearly constant level of exploratory drilling prices was maintained. After 1972 improvements in drilling technology failed to keep up with the rising prices of labour and materials inputs thus leading to a sharp increase in the price of drilling. It might be supposed that the recent surge in the price of drilling is due to drilling deeper wells since the deeper the well the higher the cost per foot, but investigation of the data on the average depth of wells drilled over time suggests that this has not been a major factor leading to higher unit costs.

2.3 Land Acquisition

Another major input into the petroleum discovery process is land. Just as one must drill wells to discover petroleum reserves one must obtain land tenure rights to drill wells. As we will see, land acquisition is a major expenditure category but before analyzing these data it is useful to describe the Alberta land tenure system under which land enters as an input into the discovery process.[3] The Alberta Department of Energy and Natural Resources (formerly Mines and Minerals) issues geophysical licences and permits to operate geophysical equipment which gives non-exclusive right to explore most areas in the province. Under these licences and permits geophysical crews conduct geological, seismic, magnetometer, etc., surveys which provide information upon which to base the selection of areas for more extensive exploratory work. Once promising areas have been selected the next step is to obtain the exclusive right to drill for oil or gas. Prior to 1976 these exclusive rights were obtained in several different ways. The most common way was through the Petroleum and Natural Gas Reservation which gave the exclusive right to drill for oil or natural gas in a specified area. These reservations were originally issued for a period of four months but through extensions could be held for several years. The government received revenues for initial issues and extensions and from bonuses paid for these exploratory rights.

If oil or gas was discovered or the areas covered by the reservations looked very promising, holders of reservations would normally apply for Petroleum and Natural Gas Leases. The lease conveyed a longer term right (originally 21 years but after 1962, 10 years) to produce and sell oil or gas. Fees and rentals for these leases were collected by the government. One of the important features of this system was that leases could only be taken on a maximum of 50

percent of any township subject to reservations. The remainder was returned to the government to become Crown reserves. Since a lease could not be more than eight square miles or be less than a quarter section and could not be adjacent, a so-called 'checkerboard' pattern of crown reserves and leases was formed.

Crown reserves were disposed of in several ways. Those areas which were very promising because they had discoveries on them were usually sold as Petroleum and Natural Gas Leases at public tender. Gas discoveries generated Crown Reserves Natural Gas Leases. Other areas were sold as Crown Reserve Drilling Reservations which required the operator to drill at least one well to a specific formation before obtaining a lease. On balance, these properties were probably less attractive than those sold under leases. Still other arrangements were possible. To encourage exploration, so-called Block 'A' areas were designated and Petroleum and Natural Gas Permits were issued which allowed the total acreage to be converted to leases rather than the maximum of 50 percent which existed for other areas.

In 1976 a new system of granting exploration and production rights was introduced which essentially extended the Block 'A' arrangement to the whole province. All of the various categories of leases, reservations, permits, and licences were replaced with a new Petroleum and Natural Gas Licence. These licences are sold by public tender and provide the right to drill for oil and gas and convert the full acreage under the licence to a production lease. The term of the licence varies depending upon its location within one of three prescribed areas in the province. The term of the production lease is five years but can be renewed for a longer period. Production leases are also issued for the same period of time by direct sale. These leases permit retention beyond the initial term for only that portion of the lease capable of production from those rights extending down to the deepest productive formation.

It has been pointed out that the Alberta government collects fees, rentals, and bonuses on reservations, leases and licences. When extraction occurs it also collects royalties on the produced amounts. A question which naturally arises is how to divide these payments between exploration and extraction so that the costs and profits of each stage of petroleum production can be determined. It is reasonable to consider royalties as a tax on extraction and thus an element of extraction costs. It is also clearly proper to consider expenditure on outstanding reservations as an exploration expenditure. But what about other categories such as leases? Leases convey production rights and

are often acquired for this purpose but they may also be acquired on properties which never produce a drop of oil or gas. The problem then is to decide what proportion of total land holdings is for exploratory purposes and what proportion is held for extraction purposes. Any decision one way or the other is bound to be somewhat arbitrary but for purposes of this study all categories of leases are considered as land holdings for extraction purposes. Land holdings for exploration purposes are thus measured by the number of acres of Reservations, Crown Reserve Drilling Reservations, Petroleum and Natural Gas Permits, Crown Reserve Natural Gas Licences, and now also the new Petroleum and Natural Gas Licences which are under exploration.

Next it must be decided how to actually go about measuring land under exploration. In the case of exploratory drilling one is able to observe the number of feet drilled per year and use it as a measure of exploratory drilling input. In the case of land, however, one cannot directly observe the number of acres which were explored in each period since these data are simply not available. Estimates of land exploration must therefore be determined from land holdings at the end of each period and new issues and cancellations during the period. Without resorting to a formal model for determining land exploration one might first be tempted to simply use a weighted average of the end of the period amounts of outstanding acreage in the categories of land tenure rights mentioned earlier. A two period moving average is one such weighting alternative. It has the advantage of providing an improved estimate of outstanding acreages within the period, especially when they change rapidly over time as they do in this case. It also centers the data in the current year.[4]

Although the average of the end of the period amounts of outstanding acreage seems like a reasonable way to measure land input into the exploratory process it is useful to investigate the implied assumptions of this approach by developing a simple representative model. It can reasonably be assumed that acreage explored in period t is some fraction of the outstanding acreage at the beginning of t (end of period $t-1$) plus some fraction of the acreage acquired during the period. We also make use of the identity that outstanding acreage at the end of t is equal to outstanding acreage at the beginning of t plus acquisitions less cancellations. It is further assumed that cancellations are a linear function of outstanding acreage at the beginning of t and acreage acquired during the period. The rationale for this is that cancellations should be positively related to how much acreage is outstanding at the beginning of the period since cancellations result from beginning acreage being explored, and are

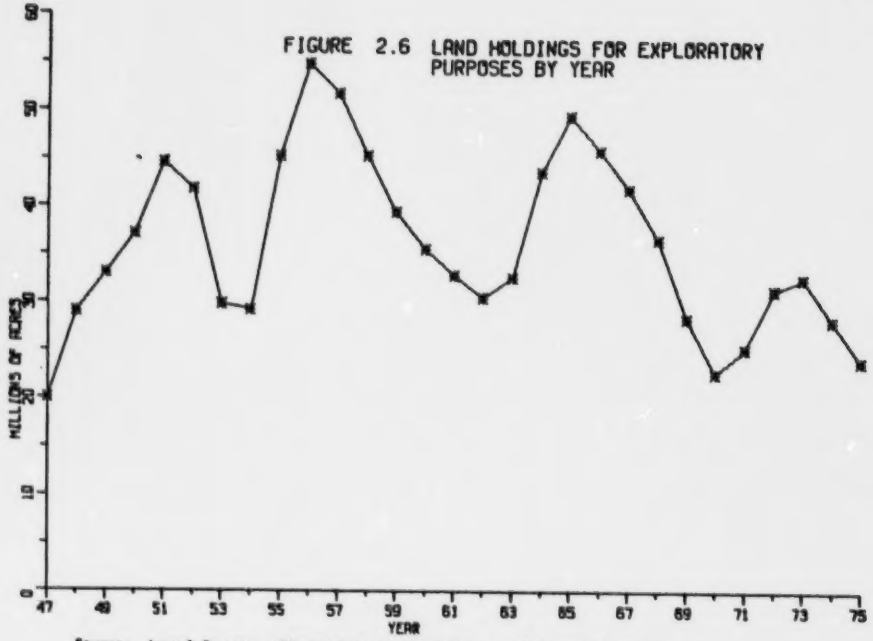
either positively or negatively related to new issues depending upon whether new issues tend to be explored and cancelled quickly or whether high levels of new issues indicate interest in holding land and thus reducing the level of cancellations. As shown in the Appendix, exploration acreage can be expressed in terms of the end of the period weighted sums. If a weight of one-half is used, as in the case of the two period moving average, then it implies that 86 percent of all acreage held at the beginning of the period and 57 percent of all new acquisitions are explored within the period of a year. Since these would appear to be reasonable numbers, it provides an added check on the use of the two period moving average as an estimate of land holdings for exploration purposes.

The pattern of land holdings in the land tenure categories noted earlier as measured by the two period moving average is shown in Figure 2.6. It reflects both response and anticipatory patterns with respect to the major plays in Alberta. Holdings rose to a high level in 1951 in response to the Leduc play which began in 1947 but holdings fell off dramatically by 1953. But in 1953 the Pembina field was discovered and again a wave of land acquisitions occurred reaching a peak in 1956 but remaining at a relatively high level through 1959, possibly in response to the Swan Hills play. One could easily argue that these were inventory cycles where inventories of land tenure rights were built up in response to major play discoveries and then drawn down again in due course. In contrast to these early cycles, the high level of holdings in 1964 and 1965 seems to anticipate the major play discovery in Rainbow-Zama rather than being a response to a major discovery. The anticipation hypothesis for this play is reasonable when one recalls that the major discovery in Rainbow-Zama was not a great surprise. It was widely felt that it was just a matter of time before the exact nature of the geology of the so-called pinnacle reefs was determined and a major find was made.

Thus we see that since major waves of land acquisition have tended to either follow or precede major play discoveries the land input as measured here would not be expected to provide a very good explanation of the discovery rate. Of course this anticipates the discussion of the exact specification of the land input and the statistical analysis of its explanatory power which are subjects examined later in this study.

Next consider the pattern of expenditure on land holdings and the prices which are derived from these expenditures. Observed expenditures in each year prior to the changes that went into effect in

FIGURE 2.6 LAND HOLDINGS FOR EXPLORATORY PURPOSES BY YEAR



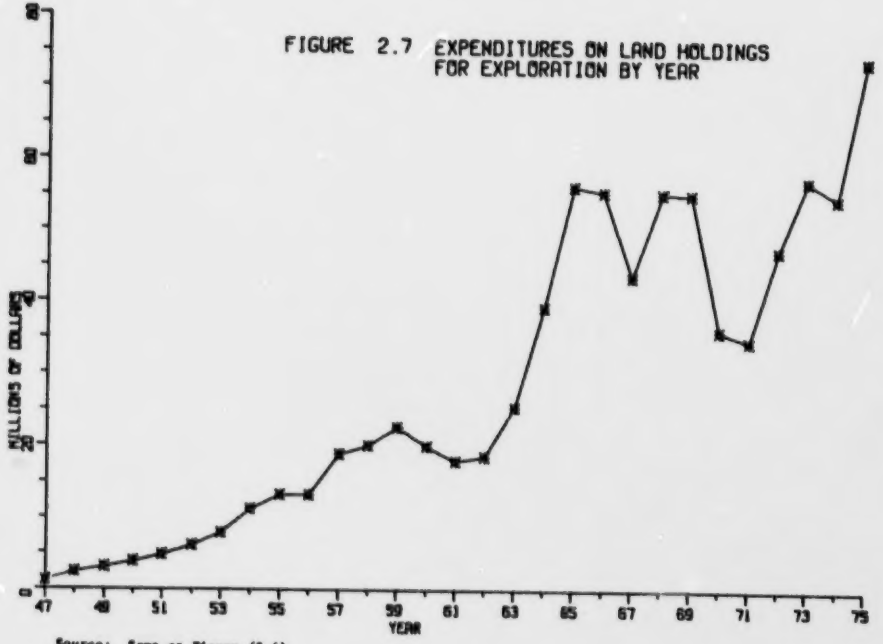
Source: Annual Reports, Alberta Department of Energy and Natural Resources (formerly Mines and Minerals).

mid-year 1976 consist of rentals on lands held during the period and fees, and bonuses on new acquisitions. Rental payments procure continuing tenure rights up to some maximum time limit whereas fees and bonuses are paid upon initial acquisition of these rights. Since land acquired in one period may be held into subsequent periods, bonus payments should be spread over the time land is held if one is to arrive at an appropriate measure of expenditure on land holdings. Unfortunately the time that each land parcel is held cannot be directly observed, at least such information is not available in published form. It will be recalled, however, that using the two period moving average of measuring land held for exploratory purposes implied that approximately 60 percent of current period issues were explored in the current period. In order to maintain internal consistency and still account for multiperiod holdings of units of land, it seems reasonable to assign 60 percent of current period bonus payments to the current period and 40 percent to the subsequent period. This implies that holdings do not extend over a two year period. Although this is obviously untrue it is an approximation which is an improvement over assigning the entire amount of current bonus payments to the current period. Thus, total expenditures on land tenure rights for exploratory purposes will consist of current period fees and rental payments and a weighted sum of the previous and current periods' bonus payments.

Figure 2.7 shows the pattern of expenditures in current dollars and Figure 2.8 shows land prices as derived from data on expenditures and land holdings.[5] The most interesting aspect of the price series is that the growth trend has grown more unstable over time. This may be due to rapidly changing supply conditions over the last ten years or so. As a region such as the Alberta sedimentary basin matures, the remaining amount of promising land parcels dwindles and accumulated information naturally allows for better discrimination among remaining prospects. One would expect such shifts in supply to result in increased land prices. As is evident from Figure 2.7 prices increased enough so that total expenditure has risen in spite of a downward, but irregular, trend in land holdings.

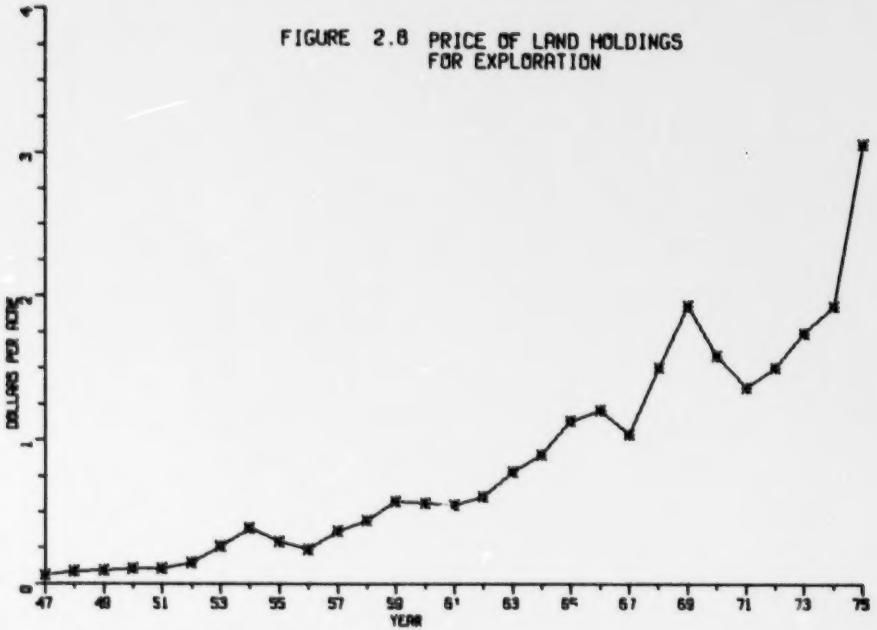
Though not shown in Figure 2.8 land prices surged upward in 1976. This was probably due to changes in land tenure arrangements under the new Petroleum and Natural Gas Licences which were discussed briefly above. The fact that bonus payments give a five year exploration term and provide a provision whereby the entire amount of the holding can be converted to a production licence, instead of just 50 percent as in the past, has greatly increased the attractiveness of land holdings.

FIGURE 2.7 EXPENDITURES ON LAND HOLDINGS FOR EXPLORATION BY YEAR



Source: Same as Figure (2.6)

FIGURE 2.8 PRICE OF LAND HOLDINGS FOR EXPLORATION



Source: Same as Figure (2.6)

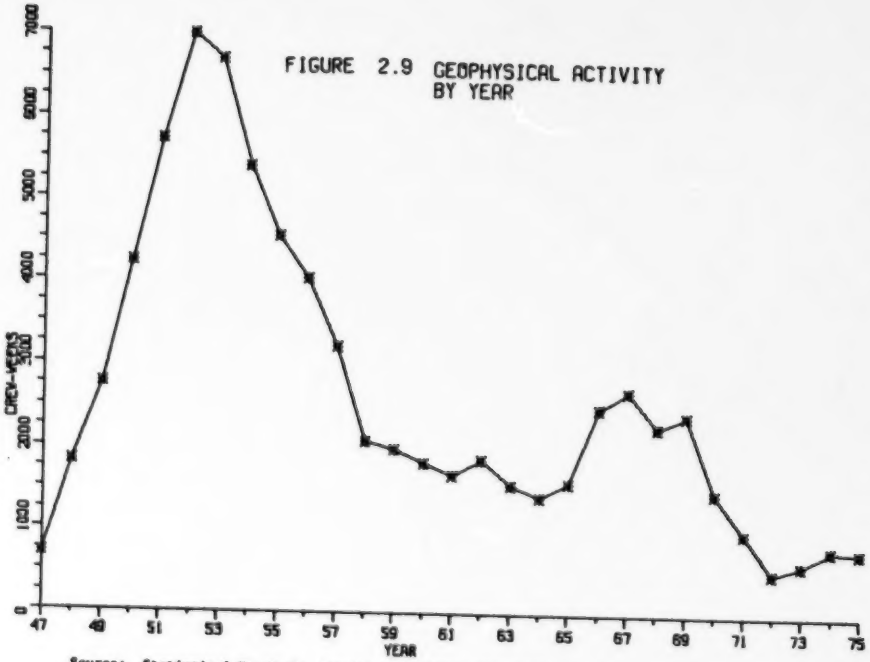
Now that the pattern of industry expenditures on land held for the purpose of exploration has been discussed it is useful to ask if this expenditure should be included as part of the costs of finding oil and gas. In economic analysis the costs of using inputs such as land in a particular activity are measured by their 'opportunity costs' which is the value of other output that must be sacrificed in order to employ the inputs in the present activity. Usually these opportunity costs can be measured simply by the market value of the inputs since they command a similar price in alternative uses. Land used for oil and gas exploration does not have an opportunity cost, however, since the land either does not have an alternative use or, if it does, its use for oil and gas exploration does not significantly interfere with its use in an alternative. Thus, even though the industry expenditures on land yields benefits to society and are legitimately part of private (industry) costs they are not part of the social costs of finding oil and gas. On the other hand, to the extent that the economic inputs embodied in exploratory drilling and geophysics have alternative employment opportunities in the economy, and it is normally assumed that they do, there is an opportunity cost of using these inputs for petroleum exploration. From a social standpoint, industry expenditures for drilling and geophysics are part of the social costs of finding oil and gas but expenditures for land tenure rights are not.

Another way of looking at this is to suppose that government carried out all exploration activity and that it did so as efficiently as the existing private sector. The only costs of finding oil and gas which would be incurred by the government are those associated with drilling and geophysics which by assumption would be the same as incurred by the private sector. The government would capture the entire return to land as part of its measured exploration profits. These profits flow to society and are the economic benefits of bringing this land into economic use. Under the existing system the government collects the rents due to land through a system of bonus payments and rentals. Under competitive conditions these returns to land would be the same in both settings and so would measured social finding costs. These arguments do not suggest, however, that land should not be considered as part of the petroleum discovery process or expenditures on it as part of private finding costs but that the return to it is largely economic rent and thus it should be excluded in calculating social finding costs.

2.4 Geophysical Activity

Geophysical survey activity involves the use of technical specialists, or crews, in combination with a variety of capital equipment, to survey land areas in search of geological structures which are likely to contain significant amounts of oil or gas or both. One would normally expect that the higher level of geophysical effort the greater the rate of new drilling site locations and hence the higher the reservoir discovery rate. The reason that this may not follow, however, is that geophysical activity not only produces new site locations it also produces information which is available for future use. Thus, past geophysical activity may be partly responsible for current discoveries. In view of this 'information effect' we would naturally expect the level of geophysical activity in a sedimentary basin to decline relatively early. This is especially true if no significant changes in structure-locating technology take place which might cause areas which had already been surveyed to be resurveyed. These arguments suggest that it may be profitable to consider a variable such as cumulative geophysical activity to represent the impact of the information effect of the current discovery rate. This will not be done but, as will be seen later, an alternative representation of this effect which allows a simpler specification of the model will be chosen. In the meantime we note that geophysical activity in Alberta has followed a general downward trend interrupted only by a sudden surge in the late 1960s.

One way of measuring geophysical effort is in terms of crew-months or crew-weeks; that is, the product of the number of geophysical crews and the number of months or weeks that they are active in a given year. Figure 2.9 shows the pattern of geophysical activity measured in this way in the Alberta sedimentary basin starting in 1947. Like land, the demand for geophysics may also respond to the discovery of major plays. The knowledge that a particular geological zone contains structures with significant accumulations of oil and gas may produce a rush of additional investigation of these zones in other locations. By the same token, success in certain zones stimulates the anticipation of finding additional producing zones. The level of activity surged upward following the Leduc play but dropped steadily after the discovery of Pembina until 1966 when, possibly in response to the Rainbow-Zama play, it grew modestly only to drop sharply again. The first two major plays in the basin generated high levels of activity in search of promising prospects in a basin which on the whole was only lightly surveyed. Presumably the reason succeeding plays failed to



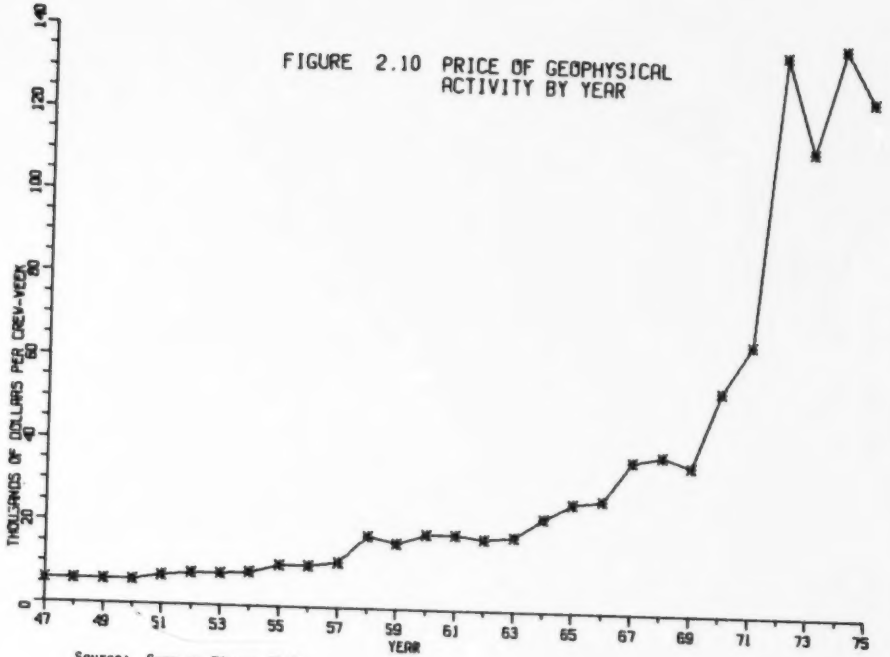
Source: Statistical Yearbook, Canadian Petroleum Association.

generate equivalent levels of activity is because of the information which had accumulated from the previous high levels of effort. This information simply allowed firms to rule out certain areas which had already been surveyed upon the location of these new producing formations. As noted above, in any basin one is naturally led to expect a downward trend in geophysical activity due to the 'information effect' even though new plays may continue to unfold over time.

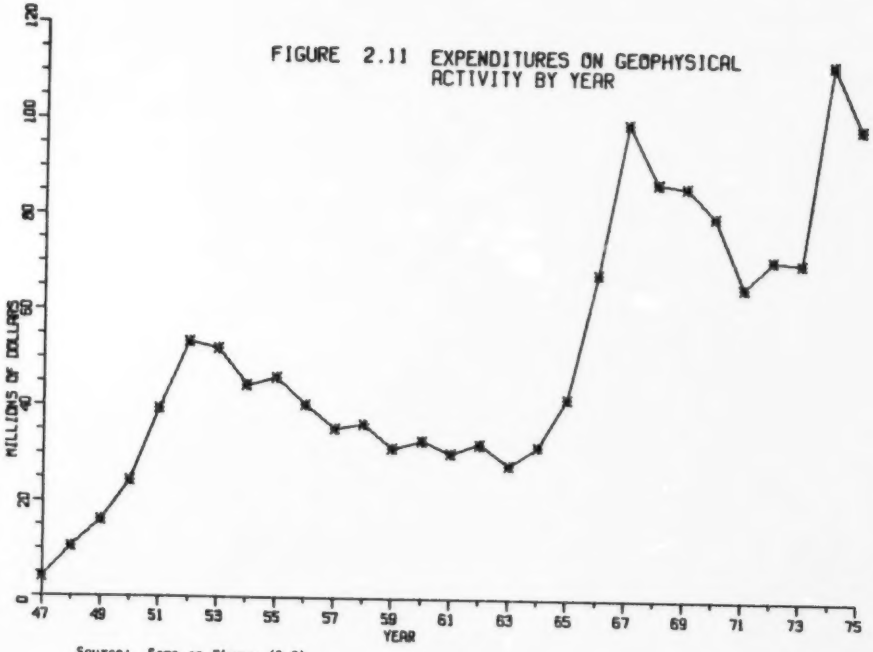
It should be noted that the use of crew-weeks as a measure of geophysical input contains some severe limitations. In view of the advances in geophysics technology, which increasingly makes use of electronic and computer equipment, a crew-week of geophysics today is not the same as a crew-week twenty years ago. The decline in crew-weeks of effort observed in Figure 2.9 thus undoubtedly overstates the actual decline in geophysical activity. An improved measure of geophysics input would involve technology adjusted crew-weeks but since data on technological change in this activity are not available such an adjustment cannot be made so that in this study unadjusted crew-weeks will be used.

The time pattern of geophysics prices is shown in Figure 2.10. Like land prices, they follow a gradual upward trend until the early 1970s after which they increase at a very rapid rate. However, the decline in the number of crew-weeks during this period is such that total expenditure on geophysical effort increased only moderately as is evident from Figure 2.11. The same caution should be used in interpreting these prices as in interpreting crew-weeks of geophysical activity.

FIGURE 2.10 PRICE OF GEOPHYSICAL ACTIVITY BY YEAR



Source: Same as Figure (2.9)



Source: Same as Figure (2.9)

Footnotes

[1]Intital recoverable reserves are calculated on the basis of current estimates of intital recoverable reserves and thus include revisions and extensions which have occurred since discovery. They do not include reserves due to enhanced recovery programs. This definition applies to both oil and gas reservoirs.

[2]The expenditure data were obtained from the Canadian Petroleum Association Statistical Yearbook. As a check, an independent source of data obtained from the Alberta Department of Energy and Natural Resources was used to estimate yearly expenditures for several recent years. The data source consisted of estimated cost-depth relationships for four separate regions in Alberta based on some 1200 statutory declarations on the costs of wells drilled in 1975, 1976, and part of 1977 and took into account all costs including rig transportation and tract or site preparation.

[3]For a more detailed description of the oil and gas land tenure system in Alberta see M. Crommelin, P. H. Pearse, and A. D. Scott, "Management of Oil and Gas Resources in Alberta: An Economic Evaluation of Public Policy," Natural Resources Journal 8 (April 1978).

[4]The data are provided on a fiscal year basis ending March 31st by the Alberta Department of Energy and Natural Resources. The two period moving average centers the data on September 15th of the preceeding year.

[5]Apart from the averaging, it should be noted that the major difference between the amount of land acquisition expenditures used in this study and that reported by the Canadian Petroleum Association is the amount of expenditures on leases from both the conversion of reservations to production leases and the direct purchase of Crown reserves. These differences are substantial, however, with those expenditures reported by the CPA in recent years being more than twice those used in this study.

Chapter 3

THE ECONOMICS OF THE DISCOVERY PROCESS

3.1 Basic Concepts

The previous chapter presented an overview of petroleum exploration in Alberta by focusing on the description and the historical pattern of behaviour of certain important variables. In this section it is shown how one can make use of the knowledge gained from this exercise to develop models of the petroleum discovery process from which it is possible to derive models of petroleum exploration costs. In the process of doing this the notion of a hierarchy of models which start at the rudimentary level of using simple trends to more complex models involving statements of formal relationships among the variables will be discussed. At a later stage each of these models will be estimated and then evaluated for descriptive accuracy and forecasting ability. I begin the process of model development by providing a description of one particular view of the petroleum discovery process and by noting certain simplifying assumptions which are made.

The essential concept in this essay is what economists call the production function. In this context the production function is simply an expression of how the exploratory inputs consisting of geophysical effort and exploratory drilling combine with land holdings to produce discoveries of oil and gas. The first thing to note is that in this view petroleum discoveries consist of two products, oil and gas. A finer classification into heavy, medium, and light crude; pure methane and gas byproducts such as butane, pentanes, etc., would be possible but it would needlessly complicate the analysis. Constraining the discovery mix to just crude oil and natural gas (including the natural gas liquids and sulphur) still leaves a multiple input, multiple output production process.

An important aspect of this process is that it is not easy to measure the quantity of inputs which are used to produce each of the products separately. All that can be observed is the levels of geophysics, exploratory drilling, and land inputs and the oil and gas discoveries which result. One cannot directly observe, for example, land input for the purpose of finding gas or geophysics input for the purpose of finding oil. This does not mean of course that such a

separation of inputs by 'intent' does not exist in the minds of exploration companies. In fact data exist for exploratory drilling effort classified by intent and attempts have been made by Eglington (1976) and Uhler (1976) to use this information to separate the oil and gas production processes in order to calculate separate finding cost functions. But a careful examination of the drilling intent data suggests that it may be seriously deficient. First, it is well known that drilling of one intent leads to discoveries which are the opposite of the original intent. Secondly, the intent data are difficult to interpret. One of the categories of intent is 'both' oil and gas and it is difficult to determine how to divide exploratory drilling in this category between oil and gas. Moreover, further study of the intent data shows that prior to 1962 substantial numbers of exploratory wells were classified with the intent of both oil and gas but after 1962 a sudden unexplained change occurred and a much smaller percentage of wells drilled were given such a classification.

The previous discussion makes it clear that unless one is willing to use drilling intent data or some other source of information for dividing inputs between the search for oil and the search for gas it is not possible to estimate finding costs for oil and gas separately. Since such estimates are an important objective of this study a suitable method for allocating the inputs must be found even in the face of the difficulties already noted. In fact, such a method is employed in this study but a detailed description of it is better left until later. In the meantime it is useful to consider the general nature of the oil and gas discovery process so that the implications of dividing it into two separate processes can be properly evaluated. But before doing this it should be noted that certain alternatives to determining separate finding costs are possible. One alternative is to convert the physical amounts discovered into a common energy unit such as the Btu and then estimate the cost of Btus. Another alternative is to calculate total finding costs for oil and gas combined which then leads naturally to the calculation of profit. The determination of the profitability of exploration is not as simple as it seems at first, however, since the market prices of reserves in the ground are typically not observed because of vertical integration in the industry. Even the purchases of Crown reserves are in fact land acquisitions and the amount of oil or gas purchased is not made public. Private sales also occur but the information is also generally not available.

Let me now turn to a discussion of the discovery process since it is the basis for the eventual estimation of finding costs and to the development of a hierarchy of models which may be used to better understand the factors determining finding costs. But first it may be useful to ask if we need models of exploration costs at all. The answer, of course, depends upon one's objectives. If the main objective is to determine the level of costs today or at a time in the past, a model is hardly necessary. On the other hand, if one wants to understand why costs were what they were and how changes in physical and economic conditions affect them then some sort of model is necessary.

The most rudimentary kind of model is one which uses time to act as a proxy variable for a number of economic and physical factors which affect costs. It is commonplace to attempt to establish trends in the data which can be used to describe the past and possibly to forecast the future. Another similar, but slightly more advanced, model would use past costs to predict their current level. This type of model presumes that the basic factors affecting past costs will behave in some regular way so that the model will prove useful in forecasting the future. One of the basic weaknesses of this type of model, however, is that it will fail to give proper weight to abrupt changes in the underlying economic and physical conditions. Of course, it is easy to find fault with these two kinds of models but whether or not more sophisticated models which explicitly incorporate economic and physical conditions do better is yet to be determined. Possibly the best way to understand how physical and economic factors are expected to affect exploration costs is to first discuss some of the general properties of the production function. The production function assigns values to the outputs (oil and gas discovery rates) for a given level of the exploratory inputs and any other relevant variables.

In Chapter 2 the characteristics and importance of petroleum plays were discussed. It is useful now to describe the general nature of the production function for plays. A basic feature of most petroleum plays is that they exhibit limited trade off possibilities between oil and gas discoveries. The situation is usually such that geological structures are located whereupon drilling determines the product mix and the quantities contained within the structure. The oil-gas mix within a reservoir and among the reservoirs within a play is mainly determined by the basic characteristics of the play and is not subject to choice. Figure 3.1 illustrates roughly what the production possibilities might look like for a typical play. The curve represents the product mix that can be discovered per unit of time with a given

FIGURE 3.1

TRADE OFF POSSIBILITIES

IN PLAY #1

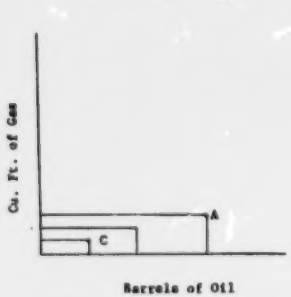


FIGURE 3.2

TRADE OFF POSSIBILITIES

IN PLAY #2

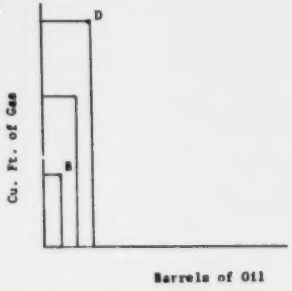
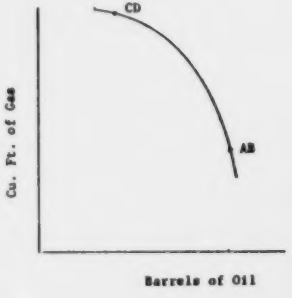


FIGURE 3.3

TRADE OFF POSSIBILITIES

FOR BOTH PLAYS



amount of exploratory effort. The shape of the curve is such that attempts to reallocate these inputs to discover more of one product at the expense of another simply cannot result in changes in the product mix. Though this is not quite true since limited trade off is possible it is close enough for illustrative purposes. For example, the reservoirs in the D2 and D3 play contained oil with significant amounts of associated and solution gas in a rather fixed proportion to oil so that trade off possibilities are obviously limited. In other plays the product mix may even be more limited and in certain cases the production function may degenerate to a single output dimension. This would be especially true for certain gas producing formations which produce no oil at all.

It is, of course, recognized that this representation of the production function is very much simplified. First of all we cannot obtain a certain output mix for any input allocation. The nature of the business is such that the output mix is clearly probabilistic or uncertain, but this feature has been studied elsewhere, Uhler (1976). Secondly, points on the curve near the axes are not possible. Allocating the total amount of effort to one intent category will still yield discoveries of the unintended product both in the form of associated product and in the form of structures containing the unintended product. For example, in the early exploration of the Alberta basin, relative prices of oil and gas were such that the industry probably would have preferred to discover much less gas than it did and allocated exploratory effort with this intent.

The curve shown in Figure 3.1 is a level curve in the sense that it represents product mixes which can be obtained from a given level of exploratory effort. Increases in exploratory effort shift the curve away from the origin and decreases shift it toward the origin. Though the effect of exploratory effort on the curve is fairly obvious there are factors besides these inputs which dynamically shift the curve. They may be thought of as the underlying physical conditions referred to earlier and are: (1) remaining undiscovered reserves in the play, and (2) the state of geophysical knowledge of the play formations. The effect of smaller remaining reserves in the play would be to shift the curve toward the origin. The reason, of course, is that if there are smaller amounts remaining to be found then a given level of exploratory effort would be expected to result in fewer discoveries. The effect of higher levels of geophysical information is to shift the curve away from the origin. To account for these factors in estimating production functions one must be able to observe and measure their values. But undiscovered reserves are clearly unobservable and how

does one measure information? Measurable proxy variables for these factors must therefore be found.

Time is a possible choice. When a new play is discovered the combination of geophysical information and exploratory drilling usually results in a rapid rise in the discovery rate. But as time passes increments to knowledge about the play become less useful in terms of their effect on the discovery rate and the effects of reduced remaining undiscovered reserves leads to a decline in the discovery rate. This suggests then that from the beginning of a new play the discovery rate should at first rise and then decline. In some cases, however, plays are dominated by a single very large reservoir which is the first reservoir discovered in the play, in which case the discovery rate rises abruptly and then declines. In any case, the period over which the discovery rate rises is usually relatively short.

Although the pattern over time of first a rise and then a fall in the discovery rate is commonly observed, time is not necessarily the best variable to use to explain this effect on the discovery rate. Time does not produce information nor does it deplete undiscovered reserves. A better choice would be a variable which had a more direct effect on information and remaining undiscovered reserves. Two possibilities come to mind: (1) cumulative exploratory effort in the play, and (2) cumulative discovered reserves in the play. Cumulative effort clearly produces information and has a direct impact on remaining undiscovered reserves. One would expect that increases in this variable would initially result in a growth in the discovery rate within the play up to some point after which further increases would result in a decline in the discovery rate. Unfortunately one cannot observe cumulative effort which is specific to a play simply because, as has already been pointed out, one cannot observe play specific exploratory effort. It is possible, however, to observe cumulative discoveries in a play; the second alternative listed above. It can be expected to have approximately the same impact on the discovery rate as cumulative effort. The information effect of geophysical effort noted earlier enters the model through its association with cumulative discoveries. As cumulative discoveries within the play increase, information is obtained which leads initially to increases in the discovery rate. But increases in cumulative discoveries, by definition, also lead to a decline in undiscovered reserves and hence a decline in the discovery rate. Thus the impact of increases in this variable in terms of its effect on the production function illustrated in Figure 3.1 would be to result in outward shifts initially followed

by inward shifts as the effect of declining undiscovered reserves began to dominate.

Now consider the general character of a production function for the discovery of oil and gas which is the aggregate of the production functions of two or more plays. For purposes of discussion consider the case of two plays. Figures 3.1 and 3.2 illustrate the trade off possibilities implied by the production functions for each play. In each case the within play trade off possibilities are limited with one being primarily an oil play and the other a gas play. The diagrams illustrate the oil-gas mixes which are possible from different amounts of exploratory effort in each play. As play specific effort rises the curve shifts outward as illustrated by several contours in the diagrams. Now consider a fixed amount of effort to be allocated between the two plays. One such allocation may involve point A in play #1 and point B in play #2. This would produce point AB in the aggregate function shown in Figure 3.3. The same amount of exploratory inputs could be reallocated so that fewer inputs were allocated to play #1 and more to play #2. This might produce a new mix of discoveries in each play illustrated by points C and D in play #1 and play #2 respectively. The point CD in Figure 3.3 is the aggregate mix of oil and gas discoveries produced by this amount of exploratory effort. Various allocations of the inputs between the two plays can be made producing an aggregate production possiblilities curve which might look something like that shown in Figure 3.3. The inter-play trade off possibilities show up quite clearly in this diagram whereas they clearly do not exist within each play. The choice of the oil and gas discovery mix on the production possibility curve depends, as usual, on their relative prices. For example, rising gas prices would result in a movement along the curve to a higher gas-oil mix. This is done, of course, by reallocating exploratory inputs toward possible gas producing formations.

The effects of cumulative reserve discoveries in each play on the aggregate production possibility curve are difficult to illustrate graphically. The aggregate curve will shift in response to shifts in the play specific curves but the nature of the shift in the aggregate curve depends upon the occurrence of new plays and the stage of the maturity of the old ones. Further discussion of this effect is better left until the formal model is introduced.

When the input allocation between oil and gas intent exploratory effort can be identified there is a production possibility set of discovery mixes for both oil intent and gas intent exploratory effort.

Thus the across play production possibility curve for oil intent inputs would look something like Figure 3.1 except that it would have some curvature, i.e., one with a high oil to gas mix with limited trade off possibilities and the across play production possibility curve for gas intent inputs would have a high gas to oil mix also with limited trade off possibilities. Changes in relative prices of oil and gas would be expected to lead to a reallocation of inputs by intent but a model which separates the discovery processes into two independent processes as is done here will not allow the impact of such price changes to be determined within the model.

3.2 Models of the Discovery Process

To formalize these matters and to introduce functional structure into the arguments it is useful to start by assuming that drilling, land, and geophysics inputs can in fact be associated with plays so that the production function for, say, oil discoveries in the ith play may be written as:

$$y_{oi} = f_i(x_{oi};R_{oi}) \qquad 3.1$$

where y_{oi} is the discovery rate of oil; x_{oi} is a vector of the three exploratory inputs searching for oil; drilling, land, and geophysics; and R_{oi} is cumulative oil reserves discovered up to the beginning of the period. The last variable represents the physical situation with respect to the effects of remaining undiscovered reserves and of geophysical knowledge which were discussed above. Equation 3.1 is now written in the following form:

$$y_{oi} = h_i(x_{oi})\phi_i(R_{oi}) \qquad 3.2$$

Writing the production function in this way means that the effects of R_{oi} on y_{oi} are separable from the effects of x_{oi} on y_{oi}. If the play specific allocations, x_{oi}, were in fact observable then after specifying appropriate functional forms for $h_i(x_{oi})$ and $\phi_i(R_{oi})$, Equation 3.2 could be estimated and finding costs in each play could then be determined. But since the play specific oil intent exploratory inputs are not observable, Equation 3.2 must be aggregated over all plays yielding

$$y_o = h(x_o)\Sigma_i\phi_i(R_{oi}) \qquad 3.3$$

where $y_o = \sum_i y_{oi}$ and x_o is a three element vector of the total of each input devoted to the search for oil. Since all of the variables in Equation 3.3 are observable it can theoretically be estimated after specifying suitable funcional forms for $h(x_o)$ and $\sum_i \phi_i(R_{oi})$.

Consider $\sum_i \phi_i (R_{oi})$ first. It has already been noted that the effect on y_{oi} and hence on y_o of increases in R_{oi} is to first cause a rapid rise in the discovery rate followed by a sharp decline which tends to level off as R_{oi} continues to grow. This behaviour may be approximated by the negative exponential form so that across all plays the effect of the R_{oi} can be approximated by:

$$\sum_i \phi_i(R_{oi}) = \sum_i d_i a_i \exp(-b_i R_{oi}) \qquad 3.4$$

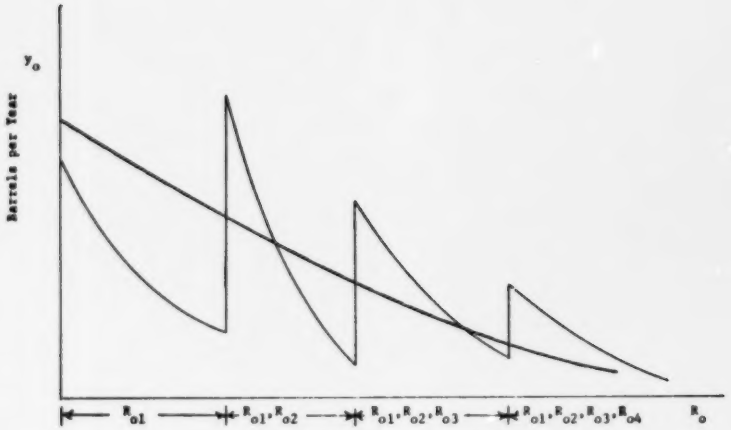
where d_i is a dummy variable which is zero prior to the discovery of the ith play and one thereafter, and a_i and b_i are parameters. If the total reserves discovered, $\sum_i R_{oi} = R_o$, is plotted on the horizontal axis and the discovery rate, y_o, on the vertical axis the effect of the function given by Equation 3.4 would look something like that illustrated in Figure 3.4. The behaviour of this function approximates the behaviour of the discovery rate as a function of cumulative reserves discovered in various plays. When the first play is discovered the discovery rate rises sharply followed by expontential decline. When the next play is discovered the aggregate discovery rate is then the sum of the discovery rates in the two plays. The effect of the second play is to increase the discovery rate sharply again with the aggregate discovery rate over the two plays declining as the sum of the exponential declines in each play. This process is repeated over all the plays in the basin thus creating the spiked function in Figure 3.4. It is of course clear that in this model the time of the discovery of a play is an exogenous event, i.e., one which is determined outside of the model.

Superimposed upon the spiked curve in Figure 3.4 is a smooth continuous function which might serve as an approximation to the spiked curve. It is of negative exponential form itself and will be used in estimating a production relationship that does not take the occurrrence and structure of individual plays into account but instead only considers the effect of cumulative total reserves discoveries. The production function which represents this aggregate relationship is given by:

$$y_o = h(x)\phi(R_o) \qquad 3.5$$

FIGURE 3.4

Oil Discovery Rate vs Cumulative Reserves



where

$$\phi(R_o) = A_o \exp(-\beta_o R_o) \qquad 3.6$$

One of the main reasons for considering the aggregate model given by Equations 3.5 and 3.6 is to see how aggregation across plays affects the predictive capability of the model. If it does reasonably well then it is an attractive alternative to that given by Equations 3.3 and 3.4.

So far I have concentrated on modelling the oil discovery function. One might suppose that the same functional specification could be applied to modelling gas discoveries but a study of Figure 2.2 suggests that the structure of gas plays in Alberta is even more complex than oil plays. In fact it was suggested earlier that in Alberta gas plays have never existed in the true sense because plays are as much an economic phenomenon as they are a physical one. In other words the right economic circumstances must exist to generate high levels of exploratory activity which result in rapid increases followed by sharp declines in the discovery rate. Such conditions have not typically existed for gas so the discoveries in particular formations tend to be spread out over long periods of time, sometimes with several peaks in the discovery rate. This pattern is clearly evident in Figure 2.2. Thus gas discoveries do not lend themselves to play analysis. Instead a model similar to that given by Equations 3.5 and 3.6 which uses the gas intent inputs and aggregate cumulative gas reserves discoveries will be formulated and is given by

$$y_g = h(x_g)\psi(R_g) \qquad 3.7$$

where

$$\psi(R_g) = A_g \exp(-\beta_g (R_g - k)^2) \qquad 3.8$$

and where y_g is total gas discoveries, x_g is a three element vector of the gas intent inputs, and R_g is cumulative gas discoveries aggregated over all gas plays. The function given by Equation 3.8 allows for a relatively slow growth in the gas discovery rate followed by a decline for any given set of gas intent inputs.

One additional model is formulated to test the significance of changes in the price of oil and gas on its discovery rate. Normally such a price effect does not impinge directly on the production function but is felt through its effect on the choice of the employment

levels of the inputs. For example, the usual effect of a rise in the price of the product being produced is to increase the level of employment of the inputs thus resulting in a higher output rate. It has been suggested however that in oil and gas exploration price may have an effect on the discovery rate in addition to its effect through the choice of the level of exploratory effort because of its effect on what is reported as a discovery, the argument being that higher prices lead to more commercial discoveries. Such a direct price effect can be tested by simply specifying a discovery function which includes price explicitly. For the gas discovery model given by Equation 3.7 the following simple alternative would allow such a price effect to be included:

$$y_g = h(x_g)\psi(R_g)g(p_g) \qquad 3.9$$

where $g(p_g)$ is an appropriate function of the wellhead price, p_g, or one might use instead the price of gas reserves in the ground. If, for example, $g(p_g) = p^{\gamma}$ then $\partial \ln y_g / \partial \ln p_g = \gamma$ which is the direct discovery rate price elasticity. The significance of this price effect will be tested empirically and the results discussed in the following chapter.

To complete the specification of the oil and gas discoveries models only the input function $h(x)$ remains. The specification used in this study is the so-called translog form given by:

$$\ln h(x) = \alpha_{00} + \sum_i \alpha_{oi} \ln x_i + \frac{1}{2}\sum_i \sum_j \alpha_{ij} \ln x_i \ln x_j$$

$$\alpha_{ij} = \alpha_{ji}; \quad \sum_o \alpha_{oi} = 1 \qquad 3.10$$

$$\sum_j \alpha_{ij} = 0 \quad i = 1,2,3$$

where the x_i are the inputs of either oil or gas intent depending upon the model in question. The subscripts differentiating between oil and gas intent inputs have been dropped for convenience. The translog specification is convenient because it allows a wide range of substitution possibilities among the inputs. Estimates of these substitution possibilities are presented and discussed in the next chapter.[1]

[1]It should be noted that the specification of $h(x)$ as translog does not imply that $h_j(x)$ of Equation 3.2, which is the play specific input function, is translog.

Chapter 4

DATA, ESTIMATION, AND EMPIRICAL RESULTS

4.1 Data

The data for this study were derived from several sources which are referenced in the figures in Chapter 2. Nothing more needs to be said about the data other than to note that in some cases data were available from more than one source in which case they were always checked for consistency. There are still two aspects of using the data which need to be discussed, however. The first is the method of dividing the exploratory input data between oil intent and gas intent exploratory effort and the second is the treatment of reported recoverable reserves.

Eglington (1975) reported exploratory wells drilled by intent of the operator based on data from the Imperial Oil Well File. These data contained three intent categories: oil, gas, and both, and were reported from 1947 to 1970. Since these data will be used to classify exploratory effort by intent the first question which naturally arises is how to divide the intent classification of both oil and gas between oil intent and gas intent drilling. The both category was especially important up to 1962. Its sudden drop in 1962 at first seemed like it would confuse the analysis but as will be seen later the sudden change will allow a check on the method used to divide the both category between oil and gas intent. The instructions for coding the intent both seems clearly to mean that the intent of a well classified this way was to find both oil and gas rather than either oil or gas. This means that both intent wells can be categorized as oil intent wells because if the objective was to find oil even if it also was to find gas, it is an oil well from the standpoint of this study. Thus all wells classified with intent both become oil wells in this study.

The next objective was to fill in the series for the post-1970 years for which intent data were not available. This was done by calculating the ratio of known oil well completions to the number of oil intent wells (after adding in the both intent category) for a subperiod just prior to 1970 and then dividing this into observed oil well completions in each year of the post-1970 period to get oil intent

wells. Gas intent wells were determined as the difference between the total and the oil intent wells calculated in this way. This method, of course, assumes that the oil success rate remained relatively constant, an assumption which is supported by the data in the pre-1970 years.

It was noted that in 1962 the number of wells classified with intent both dropped sharply. This allows a check on the decision to allocate all both intent wells to the oil intent category. One would expect the oil success rate (oil completions/oil intent) to remain fairly constant over short periods. When all of the both intent wells are added to the oil intent the average of the success rate for pre-1962 and post-1962 is remarkably similar with low variation which adds further support to the decision to allocate all of the both intent wells to the oil intent category.

Oil exploratory footage was obtained by multiplying the ratio of oil intent wells to the total number of wells by total footage. Gas exploratory footage was determined as the residual. Land under exploration for oil was determined using the same ratio with the residual being allocated to gas. The allocation of geophysical activity between oil and gas uses the same ratio as the previous two inputs. Though these allocations are, of course, approximations they reflect the best information which is available.

The second data consideration which needs to be examined is the use of reported initial recoverable reserves in place as the output variable. For those reservoirs discovered more than five or so years prior to 1976 one would not expect significant changes since most of the adjustments of initial estimates will have taken place and any substantial increases thereafter will be a result of enhancement programmes rather than normal appreciation. However, reserves in those reservoirs which were recently discovered may be subject to adjustments in future years so that the numbers used for these reservoirs would prove to be incorrect. One alternative is to adjust these amounts using estimated appreciation curves calculated, for example, by the Alberta Energy Resources Conservation Board (ERCB). This approach was not used in this study, however. Adjustments were not made for two reasons: (1) the average appreciation curves which have been calculated are dominated by appreciation factors observed for large reservoirs, most of which were discovered years ago, and (2) an analysis of discoveries in recent years and of relatively small reservoirs indicates relatively little appreciation over time. The decision not to appreciate reported reserves in recently discovered reservoirs may

lead to some understatement of the amounts discovered but using average appreciation curves would almost certainly result in a substantial overstatement of these amounts.

4.2 Estimation and Empirical Results

As outlined in Chapter 3 there are three basic models to estimate exclusive of those which include price directly in the production function. Consider the model of oil discoveries which incorporates the impact of individual plays given by Equations 3.3 and 3.4. Taking the natural logarithm of both sides of Equation 3.3 yields

$$\ln y_o = \ln h(x_o) + \ln(\Sigma_i \phi_i(R_{oi})) \qquad 4.1$$

which is non-linear in the parameters because of the second term on the right. One approach to estimating this equation is to estimate all of the parameters simultaneously using non-linear estimation methods. The other approach, and the one which is used here, is to take advantage of the separability of the function and estimate the parameters of $h(x_o)$ in a first stage which requires only linear estimation techniques and then estimate the parameters of $\Sigma\phi_i(R_{oi})$ in a second stage using non-linear estimation techniques. The other advantage to this approach is that for all of the oil and gas discovery models $h(x)$ is of the same form and thus needs only to be estimated once. To do this it is assumed that firms in the industry maximize their profits under competitive conditions in which case the share of the ith exploratory input (proportion of total cost due to the ith input) is given by:

$$S_i(x) = \partial \ln h(x)/\partial \ln x_i = \alpha_{oi} + \Sigma_j \alpha_{ij} \ln x_j$$
$$\alpha_{ij} = \alpha_{ji};\ \Sigma \alpha_{oi} = 1;\ \Sigma_j \alpha_{ij} = 0 \quad i = 1,2,3 \qquad 4.2$$

where the subscript designating the inputs as oil intent inputs has been dropped for convenience. In view of the parameter restrictions there are only two independent share equations. They can be estimated to obtain estimates of all of the parameters of $h(x)$ except for α_{00}. The estimates are shown in Table 4.1 and are the same for all of the discovery models.

A production function is considered to be well behaved when output increases monotonically with the inputs and its isoquants are convex. The translog function does not satisfy these conditions globally so it is useful to see if the conditions are satisfied in the

TABLE 4.1

PARAMETER ESTIMATES OF THE h(x) FUNCTION

Parameter	Estimate
α_{01}	.6757 (.0515)
α_{11}	.0096 (.0097)
α_{12}	.0460 (.0118)
α_{13}	-.0556 (.0096)
α_{02}	.5154 (.0574)
α_{21}	.0460 (.0118)
α_{22}	.0073 (.0222)
α_{23}	-.0533 (.0148)
α_{03}	-.1911 (.0096)
α_{31}	-.0556 (.0096)
α_{32}	-.0533 (.0148)
α_{33}	.1089 (.0148)

NOTE: Standard error in parentheses.

regions of input space of interest here. The monotonicity conditions can be checked by evaluating $\partial \ln h / \partial \ln x_i = S_i$ to see if $S_i > 0$, $i = 1,2,3$ at all points of observation. The evaluation of the fitted shares indicates that the data in this study satisfy this condition. The convexity condition is also satisfied by the data.

It is of interest to determine the degree to which the exploratory inputs are substitutable for each other in the discovery process. One would normally suppose that exploratory drilling and geophysics are substitutable inputs. Firms have the choice of spending heavily on geophysics in order to be more certain about prospects before drilling or they may choose to drill on the basis of only limited geophysical information. On the other hand one might suppose that geophysics and land and possibly also geophysics and drilling effort are complements in production in that changes in the relative input prices, for example, would lead to more or less of both of the inputs rather than more of one and less of the other. A convenient unitless measure of the substitution possibilities among the inputs is the Allen partial elasticity of substitution (AES). Elasticities of substitution between the three inputs were calculated at each observation. They are listed in Table 4.2 for selected years and the average over the years.

The elasticity of substitution (AES) between drilling effort and geophysics, ES_{13}, is positive and very stable over time indicating that drilling and geophysics are substitutes in the oil and gas discovery process. On the other hand the AES between land and geophysics, ES_{23}, is negative and very stable over time indicating that geophysics and land are complements in the discovery process. Both of these results are consistent with earlier expectations. It was noted earlier that a crew-week of geophysics today consists of more geophysical input than a crew-week twenty years ago because of improvements in geophysics technology. If, in fact, the use of crew-weeks to measure geophysical effort understates actual effort then one would expect the amount of this understatement to be greater today than in the past. One would also expect measures such as the elasticity of substitution between drilling and geophysics to be in error and that the error would increase over time because of unrecognized improvements in technology. It is interesting to note, however, that this elasticity remained almost constant between 1947 and 1967. If technological improvement in geophysics took place over this interval then it would seem that our inability to account for it has had little impact on this measure. Only after 1970 did this elasticity begin to increase modestly. If the most significant improvements in technology occurred subsequent to 1970 then these elasticities may be somewhat overstated in magnitude.

TABLE 4.2

ALLEN PARTIAL ELASTICITIES OF SUBSTITUTION

	1947	1957	1967	1975	Mean 1947-75
ES_{12}	.316	.0001	-.102	-.348	.052
ES_{13}	1.642	1.648	1.670	1.981	1.77
ES_{23}	-2.824	-2.417	-2.350	-2.625	-2.57

SUBSCRIPT NOTATIONS: 1 - drilling
2 - land
3 - geophysics

Perhaps what is most interesting is that the AES between drilling and land, ES_{12}, is positive but generally declining between 1947 and 1957 after which it becomes negative and continues to decline. It would seem that in the early part of the exploratory history of Alberta when attractive land parcels were relatively plentiful that land and drilling were substitutes in the sense that large amounts of land could be acquired to locate relatively few good prospects to be drilled. As time passed such substitution possibilites gradually diminished which led to a decline in the elasticity of substitution. Eventually drilling and land inputs became complements in the discovery process.

It is also of interest to calculate the price elasticities of demand for the exploratory inputs. This is easily done once the elasticities of substitution have been calculated since it can be shown that the price elasticities are given by:

$$E_{ij} = \partial \ln x_i / \partial \ln w_j = S_j ES_{ij}$$

where w_j is the price of the jth input. These elasticities are shown in Table 4.3 for selected years and for the mean of the years. Of particular interest are the own price elasticities. The demand for exploratory drilling is relatively price inelastic and has remained very stable over the years but showing a slight tendency to decline. On average a one percent increase in the price of drilling has led to a 0.70 percent decrease in the amount of exploratory drilling. The price elasticity of demand for land, E_{22}, is higher but has shown a stronger tendency to decline over the years. On average a one percent increase in the price of land held for exploratory purposes has led to about a one percent decrease in land holdings. Geophysics is the most price elastic of the three inputs and this elasticity has increased over time. On average a one percent increase in the price of geophysics has led to a 1.25 percent decrease in the level of geophysical activity.

The next step in the estimation of Equation 4.1 is to estimate the parameters in the function $\Sigma\phi_i\ (R_{0i})$. Since the parameters of $h(x_0)$ have already been estimated the second stage estimation equation can be written as

$$y_0 = \hat{h}(x_0)\ \Sigma_i \phi_i(R_{0i}) \qquad 4.3$$

where $\hat{h}(x_0)$ represents the predicted value of h(x) based on the parameter estimates. It will be recalled that

TABLE 4.3

ESTIMATED OWN AND CROSS PRICE ELASTICITIES

	1947	1957	1967	1975	Mean 1947-75
E_{11}	-.685	-.689	-.683	-.641	-.692
E_{12}	.039	.000	-.019	-.089	-.008
E_{13}	.724	.689	.665	.553	.681
E_{21}	.138	.000	-.043	-.162	.009
E_{22}	-1.108	-1.010	-.978	-.895	-1.010
E_{23}	-1.245	-1.010	-.935	-.732	-1.020
E_{31}	.716	.689	.702	.923	.755
E_{32}	-.348	-.395	-.427	-.670	-.468
E_{33}	-1.063	-1.085	-1.129	-1.593	-1.250

SUBSCRIPT NOTATIONS: 1 - drilling
2 - land
3 - geophysics

$$\sum_i \phi_i(R_{oi}) = \sum_i d_i a_i \exp(-b_i R_{oi}) \qquad 4.4$$

so that the remaining parameters to be estimated are γ_{00}, a_i, and b_i for all i. Since four major oil plays: Leduc, Pembina, Swan Hills, and Rainbow-Zama will be considered there are nine parameters left to estimate.[1] These parameter estimates are shown in Table 4.4.[2] The explanatory power of the full model can probably be best seen by simply plotting the observed values of total recoverable oil reserves discovered in each year and comparing them with those which are predicted by the model. The actual discoveries are shown by the asterisk connected line in Figure 4.1 (which is the same as the upper solid line in Figure 2.1) and the predicted values from the model are shown by the line marked by squares in Figure 4.1. By most standards the fit is very good. The model hits the peaks of the plays pretty well dead on and only misses the second peaks in Leduc, 1952, and Swan Hills, 1959. It misses badly in 1964 but this is because the Gilwood play was not estimated. Considering the wildly irregular function that is being fitted the model does a reasonably good job. Note, however, that it fits less well in the last few years when discoveries were at a low level.

The finding costs of oil derived from this model are now easily determined. One simply needs to divide the known expenditures on exploratory input by the predicted discoveries to obtain predicted unit finding costs. These can be compared to the observed finding costs which are determined by dividing expenditures by the observed reserves found. Figure 4.2 illustrates the comparison between the observed finding costs (shown by the line marked by asterisks) and those predicted by the model (shown by the line marked by squares). When placed on a unit finding cost basis the differences between the observed and predicted discovery rate are amplified. This is particularly apparent in 1974 and 1975 where predicted finding costs are \$2.06/bbl and \$3.31/bbl respectively and observed finding costs are \$5.35/bbl and \$9.84/bbl respectively. The observed quantities seem too high which is probably due to reported discoveries being at too low a level. It will be recalled that in this study the decision was made not to appreciate recent discoveries on the grounds that the correct appreciation factor could not be determined. It was argued that the average oil reserve appreciation factor of eight over twenty years was inappropriate for recent oil discoveries. Nevertheless one can be confident that some appreciation will occur so that observed costs in the last two or three years are undoubtedly lower than those reported. Even a relatively modest appreciation factor of two would lower the

TABLE 4.4

PARAMETER ESTIMATES OF THE $\phi(R_{oi})$ FUNCTION

Parameter	Estimate
α_{00}	-2.324
a_1	2.064
b_1	-1.011
a_2	.599
b_2	-5.989
a_3	.370
b_3	-2.265
a_4	.259
b_4	-5.530

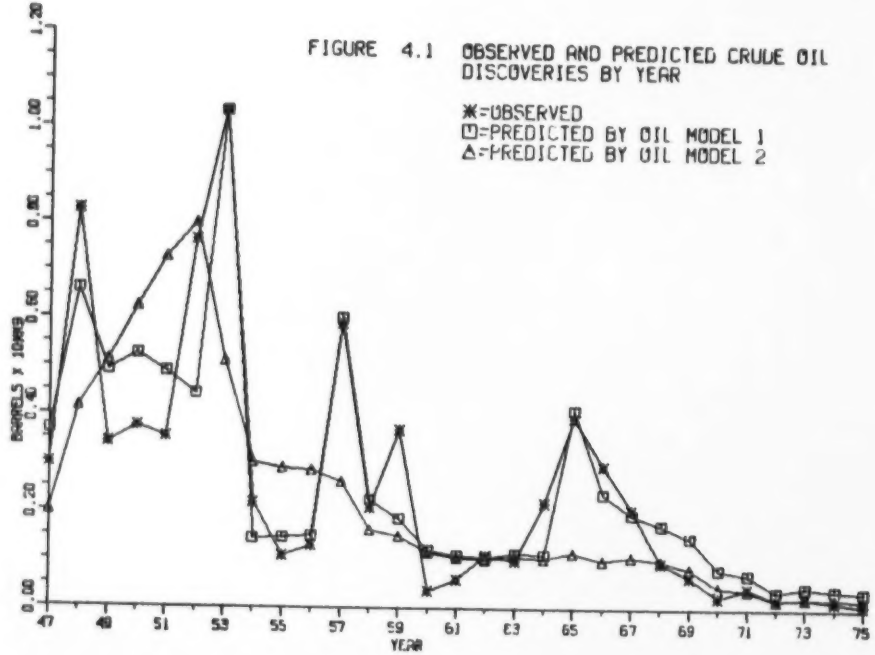
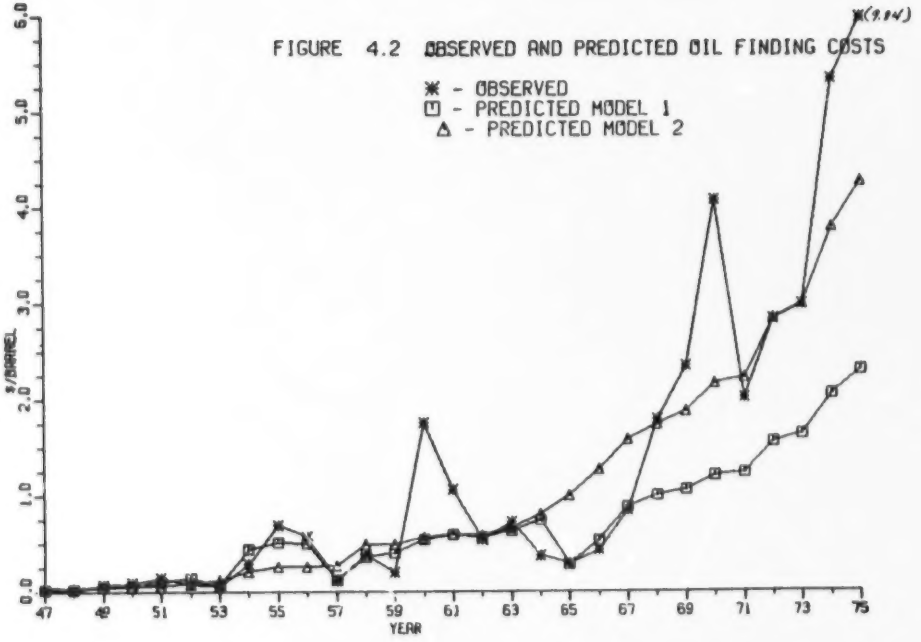


FIGURE 4.1 OBSERVED AND PREDICTED CRUDE OIL DISCOVERIES BY YEAR
*=OBSERVED
□=PREDICTED BY OIL MODEL 1
△=PREDICTED BY OIL MODEL 2
BARRELS X 10000
0.00
0.20
0.40
0.60
0.80
1.00
1.20
47
49
51
53
55
57
59
61
63
65
67
69
71
73
75
YEAR

FIGURE 4.2 OBSERVED AND PREDICTED OIL FINDING COSTS



1974 and 1975 costs to \$2.68 and \$4.92 respectively. In these years one suspects that the true finding costs are closer to those which the model predicts than to those reported as the observed.

It will be recalled that the model given by Equations 3.5 and 3.6 was also used to determine oil discovery rates. Rather than take into account the structure of oil plays cumulative discoveries were aggregated over all oil plays and then used in conjuction with $h(x_0)$ to explain discovery rates. The estimation of this model is considerably easier than the previous one since it is linear in the parameters. It is given by:

$$\begin{aligned} \ln y_0 &= \ln h(x_0) + \ln \hat{\alpha}(R_0) \\ &= \ln h(x_0) + \ln A_0 - \beta_0 R_0 \end{aligned} \qquad 4.5$$

where $\ln(x)$ is the translog form discussed earlier and A_0 and β_0 are parameters of the negative exponential form which describe the effect of cumulative discoveries across all plays, R_0, on the oil discovery rate, y_0. This model is also estimated in two stages. The parameters of $h(x_0)$ were estimated from the share equations as described earlier. After these estimates were obtained the estimated values $\ln\hat{h}(x)$ were obtained and linear regression of $\ln y_0 - \ln\hat{h}(x)$ on R_0 was used to estimate $\alpha_{00} + \ln A_0$ and β_0. An alternative which gives the same results is to leave $\ln\hat{h}(x)$ in as a regressor and constrain its coefficient to 1. The estimated equation is given by:

$$\ln y_0 = \ln\hat{h}(x_0) \underset{(.298)}{-2.198} \underset{(.055)}{-.380} R_0 \qquad 4.6$$

where the standard errors of the estimates are shown in parentheses below the coefficients. The predicted values of y are then obtained from Equation 4.6 and are plotted as the line marked by triangles in Figure 4.1. A quick glance at these values indicates that the fit of this function to the observed data is not nearly as good as it is in model 1, the first oil model. It captures the general downward trend in discovery rates but, of course, does not capture the surges due to new play discoveries. It is interesting to note, however, that it fits the observed data in recent years much better than does oil discovery model 1.

These results have some bearing on the assertion in Uhler (1975) that modelling the discovery rate using a variable which captures exhaustion and information effects which is aggregated over

all plays (R_0 in this study) rather than modelling the discovery rate on a play by play basis was likely to lead to an upward bias in the estimated discovery rate. In other words, that for any given level of cumulative reserves discoveries the estimated discovery rate would be higher than it should be because its effect is determined on the basis of plays continuing to unfold more or less as they had in the past. Since new plays are likely to become less frequent as a basin matures the discovery rate would be overestimated. This assertion in not borne out by the results of this study, however. It is clear from inspecting Figure 4.1 that the estimated discovery rate gets pulled down to a much lower level than I would have anticipated.

The oil finding costs determined by this model are plotted in Figure 4.2 as the line marked by triangles. As compared to the first model the overall poorer fit is evident but in recent years the predicted finding costs are somewhat closer to the observed. But in the last two years there is still a substantial difference possibly caused by reported discoveries being below their ultimate appreciated recoverable amounts as suggested earlier.

One additional hypothesis that was tested using this model was that the price of oil influences the discovery rate not just through its effect on the level of exploratory effort chosen but also through a direct effect on the reported level of discoveries; the hypothesis being that a higher proportion of wells drilled will be reported as successful discoveries of oil. This hypothesis was tested by including the wellhead price of oil as an argument in the oil discovery function. The estimated equation is given by:

$$\ln y_0 = \ln\hat{h}(x_0) \underset{(.546)}{-1.689} \underset{(.0561)}{-.367\, R_0} \underset{(.505)}{-.552\, \ln p_0} \qquad 4.7$$

where p_0 is the wellhead price of oil. The equation indicates that the wellhead price does not have the expected sign but it is not significantly different from zero in any case.

It will be recalled that only one gas discovery model was formulated and is given by Equations 3.7 and 3.8. Like its oil counterpart which aggregates reserve discoveries over plays, it was estimated in two stages. The first stage involved the estimating of the gas share equations to estimate the parameters in $h(x_g)$ which, as noted earlier, are identical to those estimated in $h(x_0)$. Since the fitted share equations are also tne same the Allen elasticities of substitution and the input price elasticities are the same as those

shown in Tables 4.2 and 4.3 respectively. Thus, for example, the way in which drilling effort can substitute for geophysics in finding gas is the same as it is in finding oil and the effect of changes in the price of drilling on the amount of drilling chosen is the same for gas intent drilling as for oil intent drilling.

The estimated gas discovery model is given by:

$$\ln y_g = \ln\hat{h}(x) \underset{(.257)}{-1.206} + \underset{(.245)}{.0780}\, R_g \underset{(.0004)}{-.0019}\, R_g^2 \qquad 4.8$$

Most, but not all, of the parameters of the model can be derived from these coefficients since $\beta_g = .0019$, $2k\beta_g = .0780$, and $\alpha_{00} + \ln A_g - \beta_g k^2 = -1.206$ so α_{00} and $\ln A_g$ are not estimated. But knowledge of their estimates is of little importance since they do not have a significant interpretation in any case. From Equation 4.8 it can be seen that the effect of increases in cumulative total gas reserves discoveries, other things equal, is to first increase the gas discovery rate until it reaches an estimated peak at $R_g = k = 20.5$ tcf after which it declines. In other words the estimated model suggests that the gas discovery rate grows until cumulative discoveries reach 20.5 tcf after which it begins to decline.

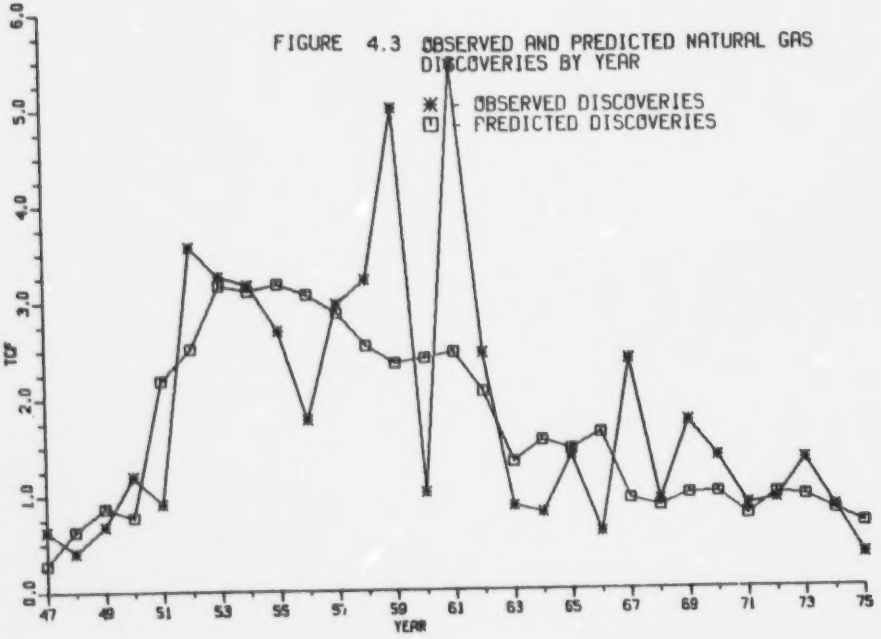
The predicted gas discoveries from this estimated model are compared with the observed gas discoveries in Figure 4.3. As in the case of the oil model which used cumulative total reserves across all plays as an explanatory variable most of the peaks representing larger discoveries in a particular year are missed. The estimated function follows the general path of observed discoveries, however, and even does a creditable job of matching them in some of the recent years.

In order to determine if the price of gas influences the gas discovery rate through its effect on what is reported as being discovered in contrast to its normal effect which acts through the choice of the level of inputs, a gas model which included the wellhead price was estimated.[3] The estimated equation which includes price is given by:

$$\ln y_g = \hat{h}(x_g) \underset{(2.340)}{+ 1.327} + \underset{(.0245)}{.0748}\, R_g \underset{(.0054)}{-.0016}\, R_g^2 \underset{(.492)}{-.536}\, \ln p_g \qquad 4.9$$

where p_g is the composite wellhead price of natural gas including NGL's and sulphur. As in the case of oil discoveries the effect of gas price on gas discoveries is of the wrong sign but not significantly different

FIGURE 4.3 OBSERVED AND PREDICTED NATURAL GAS DISCOVERIES BY YEAR



from zero. Thus the hypothesis of a direct price effect is not supported.

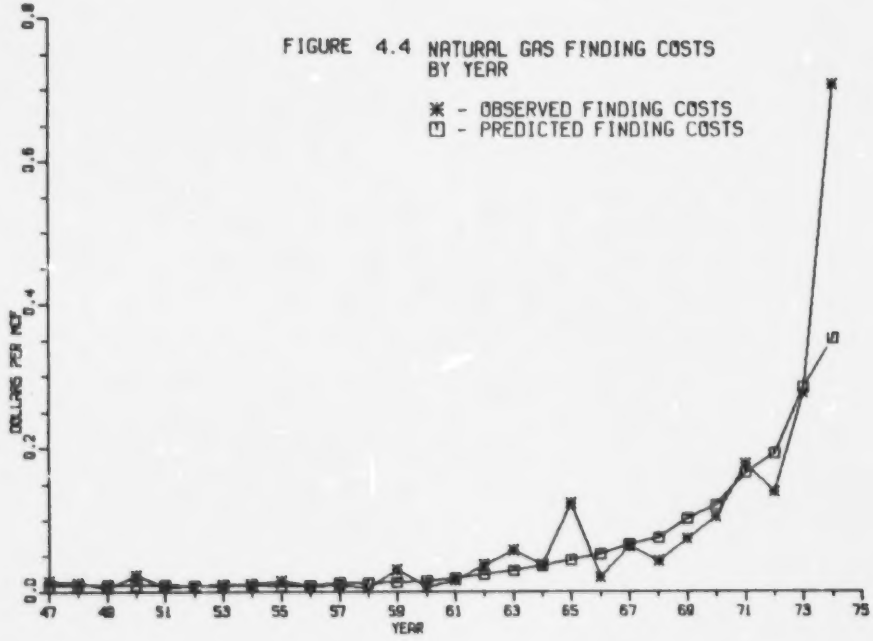
The estimated gas discovery Equation 4.8 is used to determine the predicted natural gas finding costs shown in Figure 4.4. Observed finding costs are also recorded in Figure 4.4 where it is clear that the model certainly predicts the sharp, almost exponential, rise in these costs. An inspection of the figure shows that overall the model does a relatively good job of prediction with observed and predicted finding costs being particularly close since the late 1960s with the exception of 1975 where the observed value is very high and almost twice the predicted value. But the high observed value in this year may be at least partly due to reported reserve discoveries which may still appreciate in value.

4.3 Forecasting Oil and Gas Discoveries and Their Finding Costs

Building models and estimating them from historical data has two primary purposes. The first is to learn about the past so that the structural nature of the process of interest can be better understood. This is useful in itself for all the usual reasons that better knowledge of the past is regarded as important. The second purpose is to gain enough knowledge about the structure of the process so that the model becomes a tool for forecasting the future. The second purpose is of greater interest to policy makers, for example, who want to be able to forecast conditions at least over the near term.

The ability of the models developed in the study to predict past events has been discussed in detail. What about their ability to forecast the future? In answering this question it is necessary to make clear what variables are determined within the model (endogenous) and which ones are external or given to the model (exogenous). At first it might seem that the only endogenous variable is the discovery rate which depends on the exploratory inputs and cumulative reserves. But, in fact, the exploratory inputs can be considered as endogenous because of the economic assumptions which were imposed to allow the share equations to be written. It will be recalled that firms in the industry were said to maximize profits (or minimize costs) and that competitive conditions prevailed in which case exploratory inputs would be employed up to the level where the value of their marginal product equals their price; i.e., $(\partial y/\partial x)p = w_i$, $i = 1,2,3$, where p is the product price and w_i is the price of the ith input, and total costs equal the value of what is found. It is therefore true that for any

FIGURE 4.4 NATURAL GAS FINDING COSTS BY YEAR



set of product and input prices the share equations can be theoretically solved to yield the quantities of the inputs chosen thus making inputs endogenously determined. For forecasting purposes this means that it is possible to take product price and the exploratory input prices as given and determine the level of inputs which would be chosen and then calculate the discovery rate which such a choice of exploratory inputs would yield. Forecasted finding costs are then easily determined from these data.

The most difficult aspect of forecasting oil and gas discoveries and finding costs has nothing to do with determining the level of exploratory inputs, however. In this study major emphasis has been placed on rare but significant events called plays which are of crucial significance in determining discoveries and finding costs. In the first oil discovery model, where individual plays were incorporated into the structure of the model, it is clear that the time a play begins is an exogenous event. The other models do not even formally incorporate plays. Thus it might seem that the forecasting capability of all the models in this study is limited because of their inability to forecast plays. However, all of the models can forecast discoveries in existing plays and it is my belief that a model cannot be constructed which can forecast exactly the point in time and the magnitude of a new play. Even though it may not be possible to forecast the timing of new plays exactly model 1 is the next best approximation in that when a new play is discovered its occurrence can be immediately built into the structure of the model and a new set of estimates of the model can be obtained. This also allows a new set of finding costs to be determined.

To see how a new play can be incorporated into the structure of the model and to see the special difficulties which arise, consider an attempt to incorporate the West Pembina play into oil discovery model 1. The level of the exploratory inputs is determined in theory by solving the three derived demand equations for any given set of input and output prices. For the sake of this exercise suppose that the exploratory inputs are set at a level near the 1975 level. The most obvious difficulty which arises is how to estimate the parameters a_w and b_w which are associated with the new play since very little data are available. One approach is to get a rough idea of the magnitude of the discoveries in the new play in the first year and choose the parameters a_w so that the discovery rate predicted by the model rises to the sum of discoveries in existing plays plus discoveries in the new play. Suppose the initial estimate for the new play is 200 million barrels of recoverable oil. In order to get y_0 to rise 200 million

barrels above predicted 1975 levels a_w must equal 6.56. This would then be taken as the initial rough estimate of a_w. What about the estimate of b_w? Clearly it cannot be estimated from the data since none exist beyond the current period. Probably the best that can be done is to determine if the play shows any similarity to any other plays in the basin. If it does then choose as an estimate of b_w the corresponding parameter estimate from that play. Another possibility would be to choose as an estimate the average of the $\hat{b}_i$'s over all earlier plays. Suppose it is decided to set $b_w = -3.0$ which is near the average of the $\hat{b}_i$'s in the other plays. In this case a pattern of decline in the discovery rate in the new play, other things equal, would follow an exponential decline path. By the third year after the discovery year the discovery rate in the play will have fallen to about one-twentieth of its first year level; i.e., to about ten million barrels. The cumulative amount found in the play would be on the order of 400 million barrels. It should be noted that as more data on the new play are accumulated it would be possible to revise the initial estimate of a_w and b_w.

The effect of the rapid rise in discoveries due to this play would undoubtedly be to lower discovery costs but they are unlikely to decline as sharply as discoveries increase because of the rise in exploratory expenditure which is often associated with new plays. This dampening effect on the fluctuation of finding costs is evident from the inspection of Figure 4.2. Finding costs are clearly influenced by new play discoveries but they do not fluctuate as extensively as the discovery rate of new reserves. It will be recalled from the earlier discussions that the quantities of the exploratory inputs demanded depends upon cumulative reserve discoveries in each play in addition to the input and output prices. So even if these prices remain constant the input quantities will change to affect expenditures on them and hence unit finding costs.[4]

One of the differences between a model which incorporates play effects and one, such as model 2, which does not is that for forecasting purposes the second type of model is weak. This can be seen by attempting to analyze the impact of a new play such as West Pembina using this type of model. It will be recalled that in this model the discovery rate depends upon the input function $h(x)$ and $\phi(R_0)$ and that the estimates were such that increasing cumulative discovered reserves over all plays caused $\phi(R_0)$ and hence y_0 to decline. When the new play is discovered R_0 will grow quickly causing y_0 to decline still further which is just the opposite of what should happen. Of course, as noted above, the exploratory inputs will typically grow

to some extent thus increasing $h(x)$ and hence y_o which tends to offset the decline due to R_o. The net effect on y_o will depend upon the relative importance of these offsetting effects but in all likelihood the effect of R_o will prevail. In any case the forecast would be inaccurate. If one were to wait for several years until the play had matured and then re-estimated all the parameters in the model it might appear to fit the data reasonably well because, after all, the data from the new play would be allowed to have their full impact on determining the new parameters. But the fact remains that forecasts from this type of model, when the possibility of new major plays exists, can be expected to be weak. In its defence it can be said that it requires less information than does model 1 and hence is naturally weaker in explaining the past as well as forecasting the future.

Finally it is useful to say a word about the use of forecasting techniques which use time trends in the data or related techniques which use recent observations to forecast their future values. Take finding costs as an example. It might be suggested that instead of resorting to the construction of a complete model of the discovery process from which finding costs are ultimately derived that one simply calculate observed finding costs from the data and then forecast using a time trend. Such an exercise can sometimes be quite effective but much information is lost. First it fails to account for the impact of the basic underlying factors which make finding costs what they are; namely input and product prices which determine the choice of the input expenditure levels, and of course, the all important physical factors; remaining undiscovered reserves and geophysical information. If the prices of exploration inputs were to rise suddenly for example, such models do not have the capability to recognize the impact of such changes. They clearly do not contain a structure which allows the effect of a new play discovery on finding costs to be determined. On the other hand, the models developed in this study do contain a structure which allows the determination of the impact of such events but are at the same time more complex and difficult to use.

4.4 Finding Costs and Wellhead Prices

It is of interest to compare the unit finding costs of oil and gas with their respective wellhead prices in order to gain insight into changes in the relative profitability of exploring for oil and gas, both over time and between the two products. Figure 4.5 shows the observed finding costs and the average wellhead price of oil.[5] This figure shows a substantial but narrowing margin between wellhead price

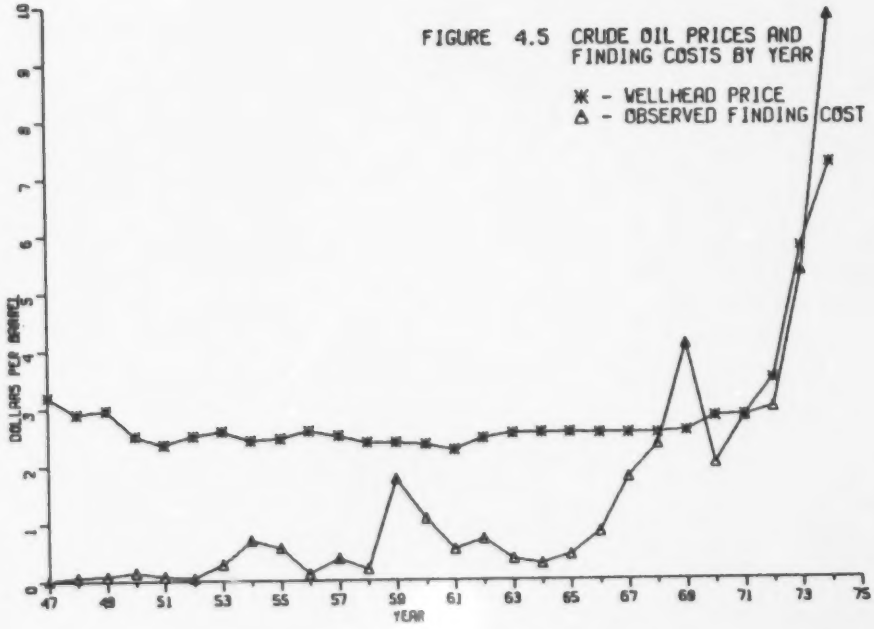


FIGURE 4.5 CRUDE OIL PRICES AND FINDING COSTS BY YEAR
* - WELLHEAD PRICE
Δ - OBSERVED FINDING COST
DOLLARS PER BARREL
0
1
2
3
4
5
6
7
8
9
10
47
49
51
53
55
57
59
61
63
65
67
69
71
73
75
YEAR

and finding costs over the years until the 1970s when it nearly disappears. For example through the 1940s and 1950s the average of the ratio of price to observed finding costs was about 40.0, in the 1960s it had dropped to 4.0, and in the 1970s it had dropped to slightly over 1.0. However, because of likely appreciation of recent discoveries which has not been included the 1970s average ratio will probably rise somewhat but these results show a clear trend of dramatically declining profitability in oil exploration. On the other hand, the West Pembina play should help to offset this situation so that over the 1970s as a whole the price-cost ratio may be much better than it appears over the first six years of this decade.

The observed finding costs and price of natural gas are shown in Figure 4.6.[6] The gas situation is somewhat more encouraging in that in the 1970s the average ratio of gas price to observed finding costs is near 2.5 as compared to 1.0 for oil. The profitability of finding gas prior to the mid-1960s appears from Figure 4.6 to be relatively good but it must be remembered that much of the gas found had a present value near zero. Although gas was being sold at high prices relative to finding costs only small amounts were being sold relative to the industry's capacity. Thus, profit incentives which might be deduced from Figure 4.6 were in actual fact much smaller. Now that the excess capacity to supply gas has apparently diminished the incentives to explore for gas are much better than for oil as evidenced by the price finding cost ratios. This explains the shift in the allocation of exploratory effort away from oil intent to gas intent drilling.[7] In 1975 approximately 75 percent of all exploratory drilling was estimated to be gas intent drilling.

The finding costs which have been discussed in this section include the expenditures on the industry's land holdings and are hence what has earlier been called private finding costs. To determine the social costs of finding oil and gas these land costs should be excluded because their opportunity cost to society is nil. A comparison of observed private and social finding costs might be made by computing the ratio of social to private finding costs. This ratio is simply the proportion of total expenditure on non-land inputs. A study of this series reveals that between 1947 and 1965 the ratio fell from about 0.9 to 0.7 after which it rose again to stabilize at about 0.8. Thus, in recent years social finding costs have been about 80 percent of private finding costs but have ranged from as high as 90 percent to as low as 70 percent.

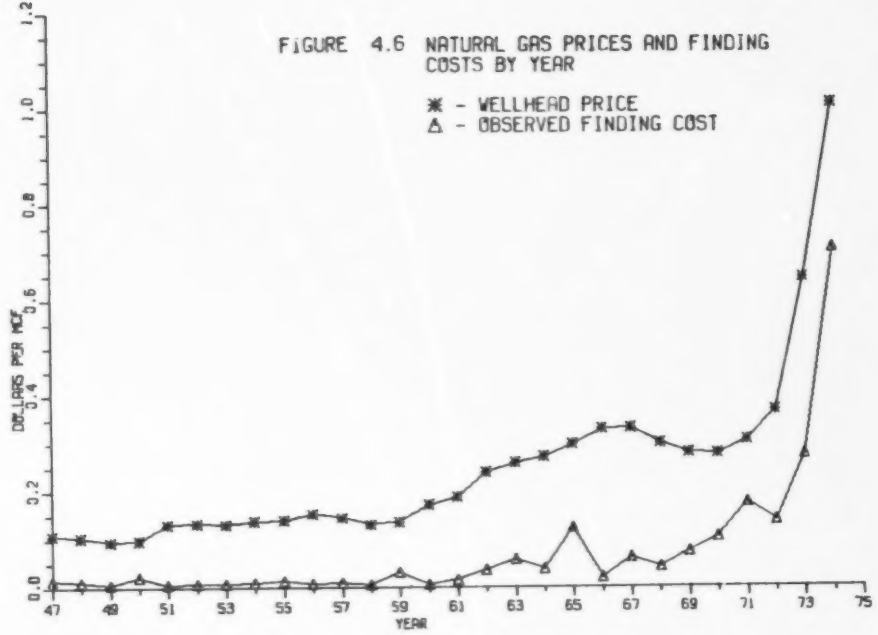


FIGURE 4.6 NATURAL GAS PRICES AND FINDING COSTS BY YEAR
* - WELLHEAD PRICE
Δ - OBSERVED FINDING COST
DOLLARS PER MCF
0.0
0.2
0.4
0.6
0.8
1.0
1.2
47
49
51
53
55
57
59
61
63
65
67
69
71
73
75
YEAR

Footnotes

[1]Gilwood is not included because of the small number of observations for this play.

[2]Note that the standard errors of the estimates have not been shown in Table 4.4. This is because they are based on numerical second derivatives and there is reason to believe these derivatives are not accurate. The numerical derivative results indicate that the asymptotic t-values are all less than 1.32 yet the improvement in the function fit over that where the a_i are all set equal to zero, i.e., when only h(x) is explaining y_0, is dramatic.

[3]The appropriate price to use would be the price of gas reserves in the ground but the wellhead price is nearly proportional to it and is thus equally useful in testing the hypothesis of a direct price effect.

[4]Recall that the demand equations are derived from $(\partial y_0/\partial x_i)\ p = w_i$ $i = 1,2,3$ so that the x_i will in general depend upon $\phi(R_{0i})$.

[5]The wellhead price is calculated by the ratio of the sales of crude oil and condensates to the volume of production in each year.

[6]The price of natural gas includes natural gas liquids and sulphur. This composite price was calculated by computing the amount of gas byproduct produced per unit of gas and then computing a weighted sum of their price using the gas byproduct to gas ratio as weights. These byproducts add substantially to the wellhead price of gas; 60 percent being a reasonable average over the years.

[7]The West Pembina play may change this again, however.

Chapter 5

CONCLUDING REMARKS

One of the primary objectives of this study was to incorporate the impact of new plays on the reserves discovery rate over all active plays and hence on finding costs. But in order to do this the occurrence of new plays was determined outside of the model. Though handling the occurrence of new plays exogenously clearly weakens the forecasting capability of the model, alternative formulations which might avoid this weakness and still keep the other features of the model do not appear to be especially promising. The basic problem is one that also occurs in other areas of investigation and is that of constructing a model which will predict a rare event. A solution to this problem may not even be possible but further research may prove to be fruitful.

It will also be recalled that the impact of changes in product prices is not determined in this model. Clearly the relative prices of crude oil and natural gas affect the allocation of exploratory inputs between each of these products. Moreover, changes in these prices affect the overall level of exploratory effort which is chosen by the industry. Though the model provided in this study can determine the impact of changes in the prices of the inputs on the level of their employment it cannot determine the impact of changes in product prices. For example, the impact of a one percent change in the price of natural gas on the amount of drilling for natural gas could not be determined. But such information is obviously valuable, especially for policy purposes. It has implications for the setting of domestic price levels and for tax policy and is thus another area of further research which would be worthwhile.

APPENDIX

The purpose of this appendix is to use a simple model to check the implications of using a two period moving average of land holdings under exploration. Let

E_t = land under exploration in period t.

L_t = land holdings for exploratory purposes at the end of period t.

I_t = new land acquisitions in period t.

C_t = land reductions (cancellations) in period t.

Assume that a fraction a_1 of L_{t-1} and a fraction a_2 of I_t is explored in period t.

$$E_t = a_1 L_{t-1} + a_2 I_t \qquad \text{A1.1}$$

By definition

$$L_t = L_{t-1} + I_t - C_t \qquad \text{A1.2}$$

$$I_t = L_t - L_{t-1} + C_t$$

Now assume that a fraction a_3 of L_{t-1} are cancelled in each period and a fraction a_4 of new issues are cancelled in period t. Thus

$$C_t = a_3 L_{t-1} + a_4 I_t \qquad \text{A1.3}$$

Combining A1.1, A1.2, and A1.3 yields

$$E_t = [a_1 - (a_2 + a_2 a_3)/(1 - a_4)]L_{t-1} + (a_2/(1 - a_4))L_t \qquad \text{A1.4}$$

This says that a weighted sum of beginning of the period land holdings are under explanation. The two period moving average assumes the coefficients in A1.4 are each 0.5. What does this imply about a_1 and a_2? To find out, A1.3 was estimated and it was found that $\hat{a}_3$ = 0.285 and $\hat{a}_4$ = -0.140. Using these estimated values, setting the coefficient in A1.4 equal to 0.5 and solving for a_1 and a_2 yields a_1 = 0.86 and a_2 = 0.57. Thus the two period moving average implies that about 86 percent of initial land holdings and 57 percent of new acquisitions are explored in the current period.

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